

STATE OF CALIFORNIA
STATE ENERGY RESOURCES
CONSERVATION AND DEVELOPMENT COMMISSION

In the matter of:)	Docket No. 93-AFC-2C
)	
Sacramento Cogeneration)	SCA'S PETITION FOR POST
Authority Procter & Gamble)	CERTIFICATION PROJECT
Cogeneration Project)	MODIFICATION TO CONSTRUCT
_____)	LM6000 TURBINE UPGRADES

The Sacramento Cogeneration Authority ("SCA") hereby submits the attached Petition for Post Certification Project Modification ("Petition") for the SCA Procter & Gamble Cogeneration Project ("Project") pursuant to Section 1769(a), Title 20, California Code of Regulations, to the California Energy Commission ("CEC"). By this Petition, SCA requests approval to modify the project description and conditions of certification as necessary to allow the construction of the LM6000 turbine upgrade and related improvements described in the Petition, which will increase the nominal generating capacity of the project by approximately 22 megawatts (MW) to 186 MW.

I hereby attest, under penalty of perjury, under the laws of the State of California, that the contents of this Petition are truthful and accurate to the best of my knowledge and belief.

SACRAMENTO COGENERATION AUTHORITY

Respectfully submitted,

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Dated: _____

12/4/2007



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PETITION FOR POST CERTIFICATION PROJECT MODIFICATION

LM6000 Fleet Upgrade



Sacramento Cogeneration Authority
Procter & Gamble Cogeneration Project
Docket No. 93-AFC-2

December 2007

Prepared for:

Sacramento Cogeneration
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1.1 Summary

The Sacramento Cogeneration Authority (SCA) proposes to modify the LM6000 turbines at the Sacramento Cogeneration Authority Procter & Gamble Cogeneration Project (P&G Facility). The modification would consist of upgrading the two LM6000PA units at the P&G Facility to LM6000PC Sprint/EFS models (water injected for nitrogen oxide [NO_x] control). These upgrades are expected to increase output by about 7.9 megawatts (MW) per turbine while reducing the carbon footprint (greenhouse gases) on a per-megawatt-hour basis. The upgrades also improve the plant's efficiency (heat rate), resulting in lower consumption of natural gas per-megawatt-hour. The additional mass flow contribution to the heat recovery steam generators may increase steam turbine output up to about 1.4 MW. Control systems would be upgraded from GE Mark V to Mark VI.

In addition, the existing LM6000PC peaker unit is proposed to be upgraded to Sprint/EFS. The peaker unit already has GE Mark VI controls. This upgrade is expected to increase output by about 5 MW while reducing the per-megawatt-hour carbon footprint. The upgrade also improves peaker efficiency (heat rate), during Sprint operations at high load (generally greater than 80% load), resulting in lower consumption of natural gas per-megawatt-hour. These combined upgrades would change conditions of certification specified in the existing SCA P&G Facility license (i.e., Commission Decision 93-AFC-2, November 1994). SCA expects changes to occur primarily in the Air Quality and Project Description sections. SCA anticipates all environmental work for the proposed upgrades will require review by and coordination with the California Energy Commission (CEC, or Commission).

Pursuant to Section 1769(a) of the Commission's Siting Regulations, SCA respectfully submits this petition for post certification project modification for the P&G Facility to modify the SCA Project Description, Air Quality conditions of certification specified in the Commission's Decision, to describe the new upgraded LM6000 Sprint turbines.

1.2 Organization of the Petition

This Petition for Post Certification Project Modification (Petition) is based on the requirements of Title 20, California Code of Regulations (CCR), section CAC 1769(a), describing the contents of post certification amendments. The Petition provides the following:

- A. A complete description of the modifications, including new language for any conditions that will be affected;
- B. A discussion of the necessity of the proposed modification;
- C. An explanation that the modification was not known at the time of the certification;
- D. An explanation that the information was not known, and why the change should be permitted;
- E. An analysis of the impacts the modification may have on the environment and proposed measures to mitigate any significant adverse impacts if appropriate;
- F. A discussion of the impacts the modification may have on the facility's ability to comply with applicable laws and regulations;
- G. A discussion of how the modification affects the public;

- H. A list of property owners potentially affected by the modification; and
- I. A discussion of the potential effect on nearby property owners, the public and parties in the application proceedings.

This Petition organization is based on SCA's determination that the effects of the LM6000 Fleet upgrade would not substantially differ from the original project evaluated in 1992-94 for any of the other environmental impact concerns.

1.3 Project Location

The LM6000 modification would be implemented within the 10-acre SCA site, adjacent to the Procter & Gamble manufacturing facility near the intersection of Power Inn and Fruitridge Roads in a highly industrialized area of the City of Sacramento. The Central California Traction Company rail line borders the site on the north and 83rd Street borders on the east. Power Inn Road is approximately 0.4 mile to the west, and Fruitridge Road is approximately 0.35 mile to the south. The site is approximately 5 miles east of the Sacramento Executive Airport and 6 miles southeast of downtown Sacramento. The local setting is shown on Figure 1-1.

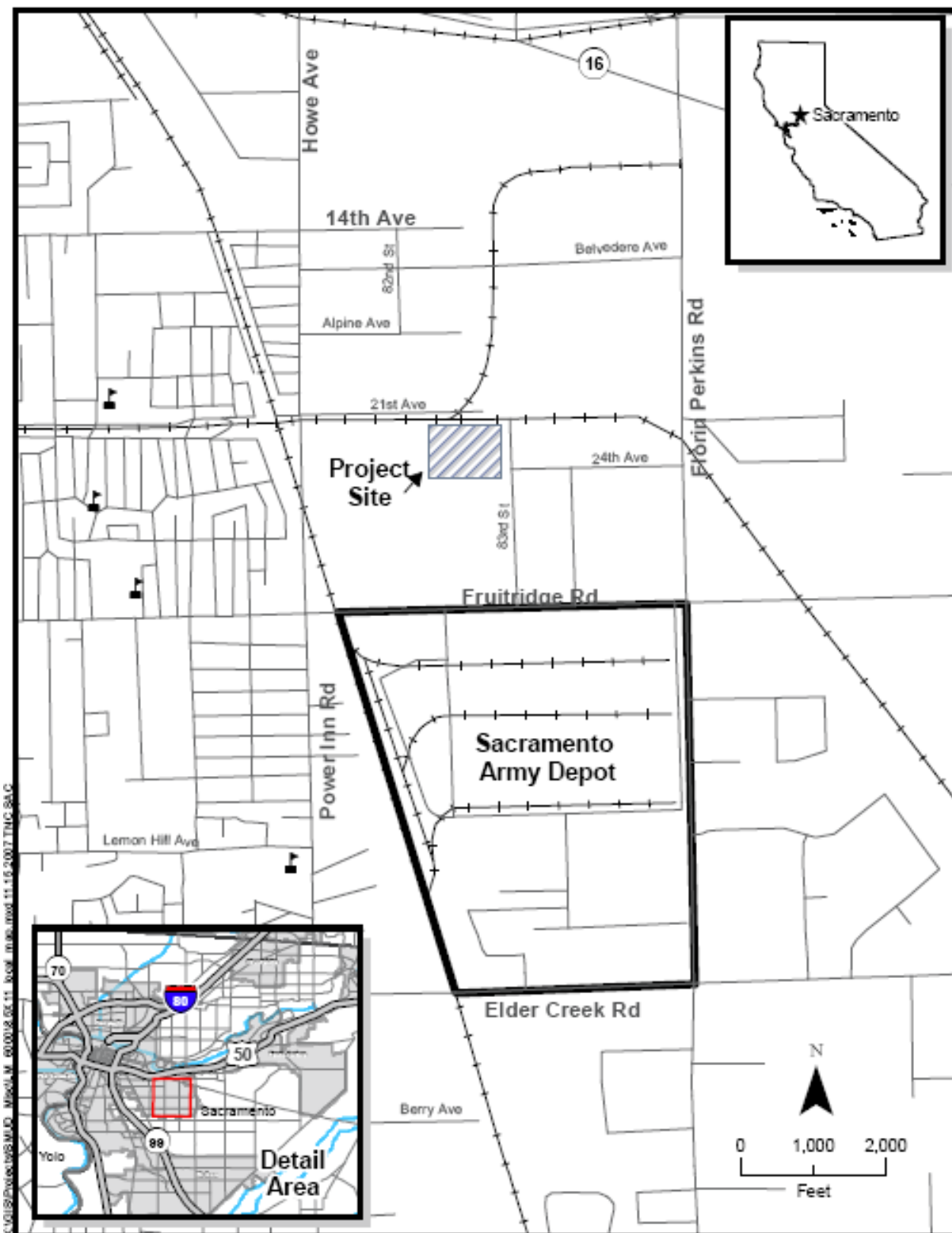
1.4 Project Background

The original project was certified by the Commission (Docket No. 93-AFC-2) on November 16, 1994. The project was constructed in 1994-95 and became operational in 1996. The SCA natural gas-fired combined cycle cogeneration plant provides up to 164 MW of electricity to SMUD and provides process steam to the existing Procter & Gamble manufacturing facility located in south Sacramento. The plant consists of the following elements:

- Combined cycle power block configured with two 42.5 MW (each, nominal) General Electric (GE) LM6000PA natural gas-fired combustion turbine generators (CTGs), two heat recovery steam generators (HRSG) with natural gas fired duct burners, and one 35 MW nominal (45 MW maximum) steam turbine generator.
- One simple cycle, natural gas-fired GE LM6000PC CTG rated at 44 MW (nominal), and
- A 1.3-mile transmission/fiber optic line to the Sacramento Municipal Utility District's (SMUD's) existing transmission system.

The project also includes four fuel gas compressors, an auxiliary boiler, and a cooling tower. Project site buildings and structures on the site include a plant control and administration building, storage tanks, switchyard, a water treatment building, a warehouse/machine shop, a chiller building, and a water chemical feed building. Figure 1-2 shows the present site arrangement.

The project is fueled by natural gas supplied by SMUD's 76-mile gas pipeline system connected from the town of Winters to three combined cycle co-generation facilities, including the Procter & Gamble Cogeneration Facility, and a 500 MW combined cycle facility.



**Figure 1-1
Sacramento Cogeneration Authority
Local Setting**

INSERT
Figure 1-2
Sacramento Cogeneration Authority
General Arrangement

Water for cooling, power augmentation and emissions control is supplied by the City of Sacramento under contract to the SMUD.

Wastewater from the project includes blowdown from the circulating water system and the HRSGs, area washdown, sanitary water, and neutralized chemical wastes. The sanitary wastewater is discharged to the County of Sacramento's sewer system. Non-contact stormwater runoff is discharged to Morrison Creek.

Upgrading the LM6000 units would be performed as part of the scheduled maintenance cycle where possible, in a manner nearly identical to the regular maintenance activity. The turbines would be removed for maintenance, as they have been more than three times apiece since initiating operations. During maintenance, the turbines would be sent to the manufacturer's depot and be fitted with additional equipment to inject water and new monitoring controls added. The upgraded turbines would then be shipped back to the facility, installed in the same turbine compartment and connected to the same infrastructure, but with an added pump skid and conveyance piping.

For the proposed upgrades, there will be a small increase in water use for evaporative cooling in the cooling tower from an increase in capacity of approximately 3 MW resulting from the PA to PC upgrade. No additional evaporative cooling in the cooling tower is required for the additional 5 MW of capacity resulting from the Sprint water injection. Any evaporative cooling effect in the compressor section resulting from the power augmentation water is lost as the water is converted to steam in the hot section of the burner and power turbine. The benefit of power augmentation water use is distinguishable by the fact that the resulting mass flow rate increase in the compressor and hot section of the turbine provides added mechanical forces to act upon the turbine blades, thereby producing more torque. The torque on the shaft produces greater amperage at a constant generator shaft speed, which in turn produces more output power.

The proposed upgrade will result in more energy being produced (approximately 7 to 8 MW) with only a slight increase in fuel flow, but less carbon dioxide (CO₂) and NO_x on a MW-hour rate basis. There would be slightly greater water use for NO_x reduction, but not more than the available water entitlement, and only a small amount of additional water will be required for cooling, in keeping with policies for powerplant cooling. There would be no changes in the plant's footprint area, the number of employees, the generation or use of hazardous materials, or the plant's visual and aesthetic conditions. The proposed work would be located within the developed area, would reduce impacts specifically to greenhouse gases, and impact avoidance measures and mitigation can be incorporated into the upgrade. As a result, this Petition is felt to be the appropriate vehicle to accomplish SCA requirement for additional generation and provides energy efficiency benefits.

1.5 Description of Proposed Changes

1.5.1 Present Generation Equipment

Present generation equipment consists of a combined cycle power block configured with two 42.5 MW (nominal) GE LM6000 natural gas-fired CTGs; two HRSGs with natural-gas-fired duct burners; one 35 MW (nominal, 45 MW maximum) steam turbine generator; and one simple cycle, natural gas-fired GE LM6000PC CTG rated at 44 MW (nominal).

The project also includes four fuel gas compressors, an auxiliary boiler, and a cooling tower. Project site buildings and structures include a plant control and administration building, storage tanks, switchyard, a water treatment building, warehouse/machine shop, a chiller building and a water chemical feed building. Figure 1-2 shows the present site arrangement.

1.5.2 LM6000 Upgrade Components

After upgrades, the equipment would incorporate LM6000 components as follows:

- Combined cycle power block configured with three 50 MW (nominal) GE LM6000PC Sprint/EFS natural gas-fired CTGs, two HRSGs with natural gas-fired duct burners and water injection, and one 35 MW nominal (45 MW maximum) steam turbine generator. Two CTGs would still be in the combined cycle configuration with the steam turbine and the peaking CTG would remain as simple cycle. A small concrete foundation, pump skid, and conveyance piping would be added for the Sprint upgrade at each of the three CTGs.
- The fuel gas compressors, auxiliary boiler, storage tanks, and cooling tower and switchyard would be the same as pre-upgrade. Buildings on the site would remain the same as pre-upgrade.

1.5.3 Construction Area

The upgrade construction area would consist of the paved and developed areas of the P&G Facility. Upgrade construction would be nearly the same as a standard turbine maintenance “change out,” in which the operating turbines are shut down and disconnected, and the surrounding structures are partly dismantled. The serviced turbines are lifted out of bearing races onto flatbed trucks and transported to the out-of-state maintenance facility. Once serviced and upgraded, the turbines are returned to the facility by flatbed; lifted into the bearing races; and piping reconnected to fuel, electrical controls and water. Control system enhancements are made at this time for compatibility with the upgraded turbines. The enclosing turbine structures are re-assembled and the turbines are tested, commissioned and cycled for operation.

In the upgrade, the LM6000 turbines would have vanes changed, additional ports for water injection installed, and upgraded control components and sensors installed. At the SCA facility, additional foundation, pump, piping for water and conduit for control systems would be installed. In all other respects the upgrade would be the same as a normal maintenance overhaul.

1.5.3.1 Construction Procedure

Each LM6000 upgrade would consist of the following steps:

- Mobilize temporary spare LM6000 to P&G Facility site.
- Shut down target LM6000 unit, allow to cool, and dismantle part of enclosure.
- Disconnect fuel, controls and water piping.
- Load target LM6000 on 45-foot flatbed trailer.
- Install spare LM6000 at P&G Facility site, connect, test and bring to operation.
- Target LM6000 is transported by road to the out-of-state service facility.

- Target LM6000 is upgraded by installation of new variable inlet guide vanes, new controls and air and water injection manifold and spray nozzles, exhaust diffuser, new LPT/LPT mid shaft and LPC stator. Upgrade takes approximately 6 to 8 weeks.
- Upgraded LM6000 is returned by flatbed truck to P&G Facility.
- The spare LM6000 is removed from service and disconnected, and the enclosure partly dismantled.
- The spare turbine is lifted from bearing races to flatbed trailer, or installed in place of the next target turbine.
- The upgraded LM6000 is lifted into bearing races, connected to existing and added equipment and commissioned for operation.

1.5.3.2 Construction Vehicles and Equipment

The actual equipment to be used to remove and transport the LM6000 for upgrading will be determined once the project is awarded, but is expected to be similar to that listed in Table 1-1.

TABLE 1-1: ESTIMATED VEHICLES AND EQUIPMENT NEEDED FOR LM6000 UPGRADE

Vehicles and Equipment	Number of Vehicles	Construction Activity
Personal transport vehicles	10 per day	Transport workers to project construction site.
Truck-mounted welding units	1 to 2	Site manufacturing.
Flatbed truck/tractor trailer	3 trucks	Delivers LM6000 for maintenance.
Wheeled grade-all	1	Unload and maneuver parts.
Tracked crane	1 to 3	Lift LM6000 from bearing races to truck.
Concrete Truck	3 to 4 x 3 days	Install small Sprint pump foundation.

1.5.4 Construction Schedule

The upgrade is proposed to be constructed in spring 2008. It is particularly important to avoid outages during the summer months, when energy use is highest. The District plans to upgrade the LM6000, according to the schedule in Table 1-2.

TABLE 1-2: PROPOSED SCHEDULE OF LM6000 UPGRADE

Activity	Date
Change out First Turbine (P&G 1A)	February 2008
Install first LM6000 (P&G 1A)	April 2008
<i>No Outages</i>	<i>June 1- September 30, 2008</i>
Change out Second Turbine (P&G 1B)	October 2008
Install second LM6000 (P&G 1B) Peaker	February 2009
<i>No Outages</i>	<i>June 1- September 30, 2009</i>
Change out Peaker	October 2009
Install Peaker	December 2009

Although is it desirable to change out and install the first turbine in spring 2008, if contract timing does not accommodate this schedule, then the first turbine changeout may be in fall 2008. The District has determined that spring and fall electrical loads are lowest and, therefore, supportable from external sources, and will accommodate summer cooling and winter heating electrical load demands.

1.6 Necessity of the Modification

SCA is a joint powers agency that owns and operates the P&G Facility. It is governed by a commission composed of the seven members of the SMUD Board of Directors. This LM6000 modification is necessitated by SMUD's policy of reducing greenhouse gas emissions, improving energy efficiency wherever feasible, and increasing electrical power production to meet growing regional demands. When SMUD has greater demands for electricity than it can meet with its own generation sources, electricity must be bought from other sources at a cost that fluctuates with the market. When replacement energy from sources outside SMUD's service area is acquired, it is normally purchased at additional cost to SMUD customer-owners. Replacement energy increases SMUD's exposure to price volatility and may lead to additional consumption of natural resources with associated environmental impacts, including air, water quality, and global climate change impacts. The cost fluctuation is undesirable for SMUD customer-owners. SMUD and SCA are motivated to produce its own power with the best efficiency and reliability, while minimizing environmental impacts. To the extent SMUD can generate and control its own sources of energy, the price volatility is lower and risk to SMUD's power supply is lower.

1.7 Modification was not Known at the Time of the Certification

The proposed project modification was not known and could not have been known at the time of the Application for Certification (AFC) submittal in 1993. The LM6000PC Sprint/EFS unit was introduced by GE in 2003 and was not available in 1993-1994, when the project was permitted.

1.8 Why the Change Should be Permitted

The proposed project modification would allow SCA to operate at a higher efficiency, producing more power with less net emissions of CO₂ per MW-hr and total NO_x than currently possible without the upgrades. The change would be consistent with SMUD's policies to improve energy efficiency and air quality, and reduce sources of greenhouse gases according to California state laws (AB 32, the California Global Warming Solutions Act of 2006).

2.1 Air Quality

The 1994 Commission Decision identified that the combustion of natural gas by the SCA would result in the emission of several air pollutants regulated by federal and state law. Pollutants for which ambient air quality standards have been established are generally referred to as criteria pollutants. The criteria pollutants include NO_x, sulfur dioxide (SO₂), suspended particulate matter less than 10 microns in diameter (PM₁₀), fine particulate matter less than 2.5 microns in diameter (PM_{2.5}), sulfates (SO₄), carbon monoxide (CO), ozone (O₃) and lead (Pb). The project is located in an area designated as nonattainment for the federal ozone and PM₁₀ standards. The air basin is considered an attainment or unclassified area for federal PM_{2.5}, CO, SO₂, NO₂, and Pb standards.

The California Air Resources Board (CARB) has designated Sacramento County as nonattainment for the state ozone, PM₁₀, and PM_{2.5} standards, and attainment for the state CO, SO₂, NO₂, SO₄, and Pb standards. Sacramento County was reported as unclassified for the state hydrogen sulfide (H₂S) and visibility reducing particles standards.

The Commission Decision noted that the project construction-related emissions would be temporary and that implementation of Conditions of Certification would mitigate the air quality impacts to insignificant levels. The Conditions of Certification required the implementation of best available control technology, including the use of natural gas fuel, water injection, selective catalytic reduction and oxidation catalysts to reduce emissions of criteria pollutants, and watering during construction to reduce fugitive dust emissions. Emissions of oxides of nitrogen (NO_x), volatile organic compounds (VOCs), and PM₁₀ were also mitigated by providing emissions offsets. The Commission Decision concluded that project construction and operation would not result in significant impacts to the environment with respect to air quality.

In addition to increasing electrical capacity, the primary goal of the turbine upgrade project is to reduce NO_x emissions and greenhouse gas (GHG) emissions per unit of electricity produced. The overall reduction in emissions per unit of energy is accomplished by installing a more modern turbine engine design (the "PC Sprint/EFS") that reduces NO_x emissions from the turbine and improves turbine efficiency. Figure 2-1 depicts the schematic diagram for the combined cycle operation at the Procter & Gamble facility. Figure 2-2 depicts the simple cycle peaker unit. Both figures show the location of Sprint injections, plus water injection for NO_x control. With implementation of the current mitigation measures, and a reduction in the allowable NO_x emission rate, there will be no net increase in NO_x, VOC, and PM₁₀ emissions above the current criteria, and the existing conditions are adequate to protect the environment for these pollutants. Increases in total CO and SO_x emissions, resulting from increased fuel flow at full load will not result in a significant air quality impact, and emissions of these pollutants will continue to meet best available control technology requirements. Therefore, in addition to complying with current laws and regulations, the existing Conditions of Certification, along with the project decreases in NO_x emissions, improvements in heat rate (turbine efficiency) are adequate to protect the environment with respect to air resources.

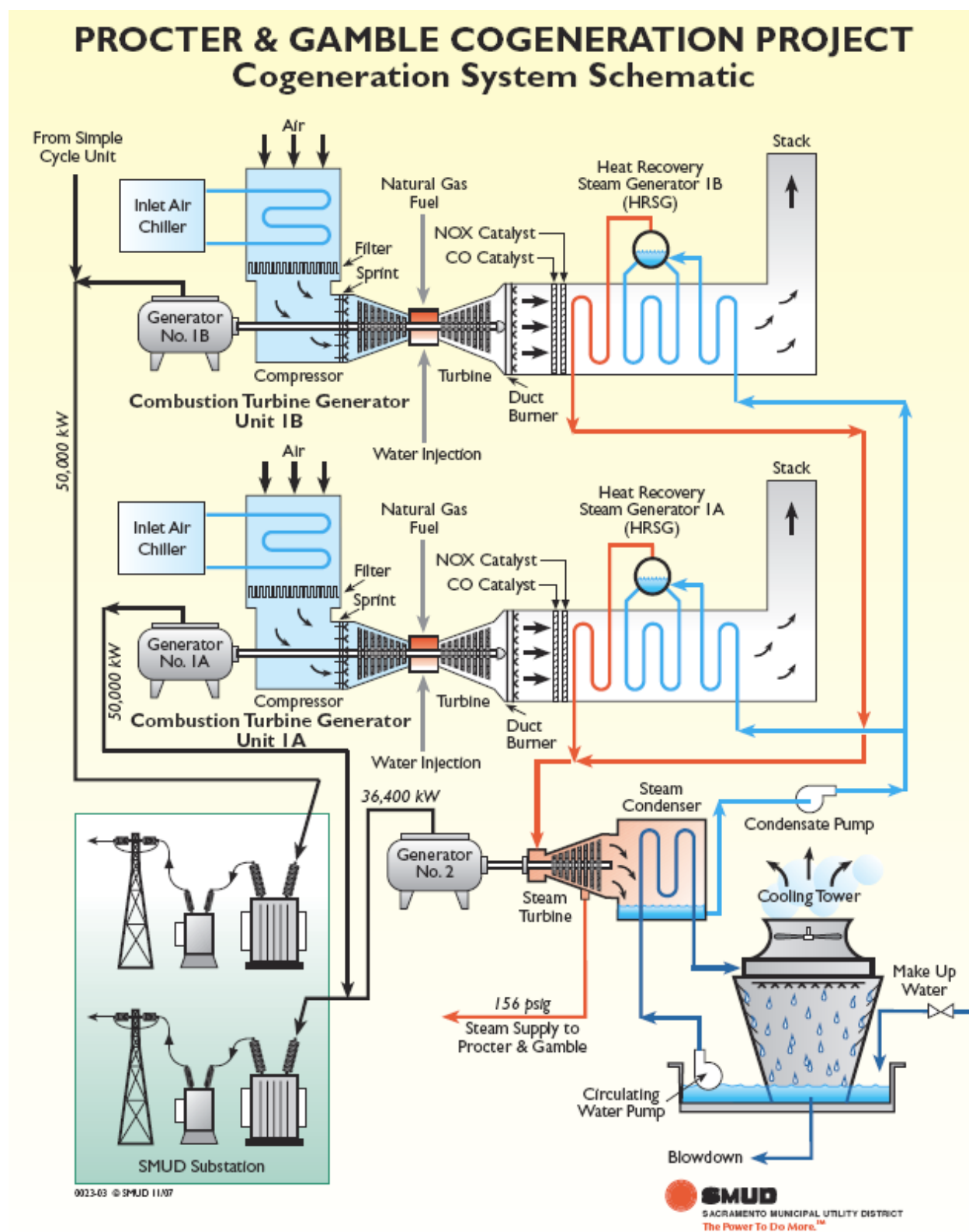


Figure 2-1
Schematic of SPRINT Operation

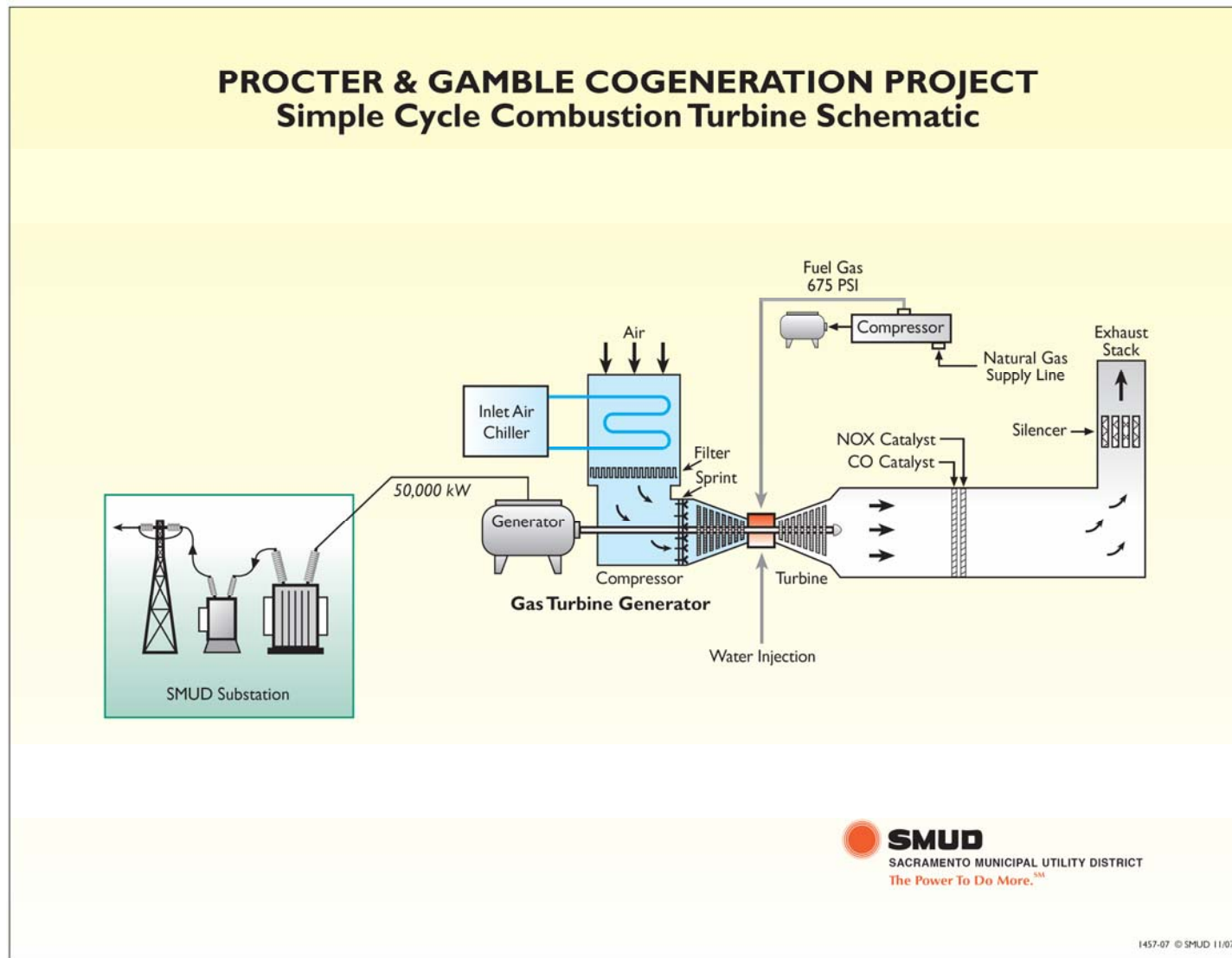


Figure 2-2
Schematic of Simple Cycle Combustion Turbine

2.1.1 Affected Environment

The project site is located in the Sacramento Valley Air Basin on a 10-acre site adjacent to the existing Proctor & Gamble manufacturing facility near the intersection of Power Inn and Fruitridge Roads in a highly industrialized area of the City of Sacramento. The Central California Traction Rail line borders the site to the north, and 83rd Street borders on the east. Power Inn Road is approximately 0.4 mile to the west, and Fruitridge Road is approximately 0.35 mile to the south. The site is approximately 5 miles east of the Sacramento Executive Airport and 6 miles southeast of downtown Sacramento.

2.1.2 Laws, Ordinances, Regulations, & Standards (LORS)

Applicable federal, state, and local laws, ordinances, regulations, and standards (LORS) that govern air quality and air pollution are discussed in this section. Specific requirements are identified and the compliance of the proposed project with these requirements is demonstrated.

2.1.2.1 Federal LORS

The United States Environmental Protection Agency (EPA) implements and enforces the requirements of many of the federal environmental laws. EPA Region IX, based in San Francisco, administers EPA programs in California.

The Federal Clean Air Act, as most recently amended in 1990, provides EPA with the legal authority to regulate air pollution from stationary sources such as the SCA project. EPA has promulgated the following stationary source regulatory programs to implement the requirements of the Clean Air Act:

- Standards of Performance for New Stationary Sources (NSPS)
- National Emission Standards for Hazardous Air Pollutants (NESHAP)
- Prevention of Significant Deterioration (PSD)
- New Source Review (NSR)
- Title IV: Acid Deposition Control
- Title V: Operating Permits

National Standards of Performance for New Stationary Sources

Authority: Clean Air Act §111, 42 USC §7411; 40 Code of Federal regulations (CFR) Part 60, Subparts GG and KKKK

Purpose: Establishes standards of performance to limit the emission of criteria pollutants (air pollutants for which EPA has established national ambient air quality standards [NAAQS]) from new or modified facilities in specific source categories. The applicability of these regulations depends on the equipment size; process rate; and/or the date of construction, modification, or reconstruction of the affected facility. The Standards of Performance for Stationary Gas Turbines (Subparts GG and KKKK)—which limit NO_x and SO₂ emissions from subject equipment—are applicable to the gas turbines. These standards are implemented at the local level with federal oversight.

Administering Agency: Sacramento Metropolitan Air Quality Management District (SMAQMD), with EPA Region IX oversight.

National Emission Standards for Hazardous Air Pollutants

Authority: Clean Air Act §112, 42 USC §7412; 40 CFR Part 63, Subpart YYYYY

Purpose: Establishes national emission standards to limit hazardous air pollutant (or HAP, which are air pollutants identified by EPA as causing or contributing to the adverse health effects of air pollution but for which NAAQS have not been established) emissions from existing major sources of HAP emissions (greater than 10 tons per year of any single HAP, or greater than 25 tons per year of all HAPs combined) in specific source categories. The SCA project is not a major source of HAP emissions, and, therefore, is not subject to Subpart YYYYY.

Administering Agency: SMAQMD, with EPA Region IX oversight.

Prevention of Significant Deterioration Program

Authority: Clean Air Act §160-169A, 42 USC §7470-7491; 40 CFR Parts 51 and 52

Purpose: Requires preconstruction review and permitting of new or modified major stationary sources of air pollution to prevent significant deterioration of ambient air quality. PSD applies only to pollutants for which ambient concentrations do not exceed the corresponding NAAQS (i.e., attainment pollutants). The PSD program allows new sources of air pollution to be constructed, or existing sources to be modified, while preserving the existing ambient air quality levels, protecting public health and welfare, and protecting Class I areas (e.g., national parks and wilderness areas). These requirements are implemented at the local level with federal oversight.

Administering Agency: SMAQMD, with EPA Region IX oversight.

New Source Review

Authority: Clean Air Act §171-193, 42 USC §7501 et seq.; 40 CFR Parts 51 and 52

Purpose: Requires preconstruction review and permitting of new or modified major stationary sources of air pollution to allow industrial growth without interfering with the attainment of ambient air quality standards. New Source Review applies to pollutants for which ambient concentrations exceed the corresponding NAAQS (i.e., nonattainment pollutants). These requirements are implemented at the local level with federal oversight.

Administering Agency: SMAQMD, with EPA Region IX oversight.

Title IV – Acid Rain Program

Authority: Clean Air Act §401, 42 USC §7651 et seq.; 40 CFR Part 72

Purpose: Requires the monitoring and reduction of emissions of acidic compounds and their precursors. The principal source of these compounds is the combustion of fossil fuels. Therefore, Title IV established national standards to limit SO_x and NO_x emissions from electrical power generating facilities. Most standards are implemented at the local level with federal oversight. However, SO_x allowance transactions and monitoring provisions including monitoring plans,

notifications, and quarterly monitoring data are still administered by federal EPA (Clean Air Markets Division).

Administering Agency: SMAQMD, with EPA Region IX oversight.

Title V - Operating Permits Program

Authority: Clean Air Act § 501 (Title V), 42 USC §7661; 40 CFR Part 70

Purpose: Requires the issuance of operating permits that identify all applicable federal performance, operating, monitoring, recordkeeping, and reporting requirements. Title V applies to major facilities, acid rain facilities, and any facility listed by EPA as requiring a Title V permit. These requirements are implemented at the local level with federal oversight.

Administering Agency: SMAQMD, with EPA Region IX oversight.

Compliance Assurance Monitoring (CAM) Rule

Authority: Clean Air Act § 501 (Title V), 42 USC §7414; 40 CFR Part 64

Purpose: Requires facilities to monitor the operation and maintenance of emissions control systems and report any control system malfunctions to the appropriate regulatory agency. If an emissions control system is not working properly, the Compliance Assurance Monitoring (CAM) rule also requires a facility to take action to correct the control system malfunction. The CAM rule applies to emissions units with uncontrolled potential to emit levels greater than applicable major source thresholds. However, emission control systems governed by Title V operating permits requiring continuous compliance determination methods are exempt from the CAM rule. Since the Project will be issued a Title V permit requiring the installation and operation of continuous emissions monitoring systems, the Project will qualify for this exemption from the requirements of the CAM rule. Consequently, the CAM rule will not be further addressed.

Administering Agency: SMAQMD, with EPA Region IX oversight.

2.1.2.2 State LORS

CARB was created in 1968 by the Mulford-Carrell Air Resources Act, through the merger of two other state agencies. CARB's primary responsibilities are to develop, adopt, implement, and enforce the state's motor vehicle pollution control program; to administer and coordinate the state's air pollution research program; to adopt and update, as necessary, the state's ambient air quality standards (AAQS); to review the operations of the local air pollution control districts (APCDs); and to review and coordinate preparation of the State Implementation Plan (SIP) for achievement of the federal AAQS.

State Implementation Plan

Authority: Health & Safety Code (H&SC) §39500 et seq.

Purpose: Required by the federal Clean Air Act, the SIP must demonstrate the means by which all areas of the state will attain NAAQS within the federally mandated deadlines. CARB reviews and coordinates preparation of the SIP. Local APCDs must adopt new rules (and/or revise existing rules)

and demonstrate that the resulting emission reductions, in conjunction with reductions in mobile source emissions, will result in the attainment of NAAQS. The relevant SMAQMD Rules and Regulations that also have been incorporated into the SIP are discussed with the local LORS.

Administering Agency: SMAQMD, with CARB and EPA Region IX oversight.

California Clean Air Act

Authority: H&SC §40910 - 40930

Purpose: Established in 1989, the California Clean Air Act requires local APCDs to attain and maintain both national and state AAQS at the “earliest practicable date.” Local APCDs must prepare air quality plans demonstrating the means by which AAQS will be attained. The SMAQMD Air Quality Plan is discussed with the local LORS.

Administering Agency: SMAQMD, with CARB oversight.

Toxic Air Contaminant Program

Authority: H&SC §39650 - 39675

Purpose: Established in 1983, the Toxic Air Contaminant Identification and Control Act creates a two-step process to identify toxic air contaminants (TACs) and control their emissions. CARB identifies and prioritizes the pollutants to be considered for identification as TACs. CARB assesses the potential for human exposure to a substance while the Office of Environmental Health Hazard Assessment evaluates the corresponding health effects. Both agencies collaborate in the preparation of a risk assessment report that concludes whether a substance poses a significant health risk and should be identified as a TAC. In 1993, the Legislature amended the program to identify the 189 federal hazardous air pollutants as TACs. CARB reviews the emission sources of an identified TAC and develops, if necessary, air toxics control measures (ATCMs) to reduce the emissions. This program is implemented at the local level with state oversight.

Administering Agency: SMAQMD, with CARB oversight.

Air Toxic “Hot Spots” Act

Authority: H&SC §44300-44384; 17 CCR §93300-93347

Purpose: Established in 1987, the Air Toxic “Hot Spots” Information and Assessment Act supplements the TAC program, by requiring the development of a statewide inventory of TAC emissions from stationary sources. The program requires affected facilities to prepare (1) an emissions inventory plan that identifies relevant TACs and sources of TAC emissions; (2) an emissions inventory report quantifying TAC emissions; and (3) a health risk assessment, if necessary, to characterize the health risks to the exposed public. Facilities whose TAC emissions are deemed to pose a significant health risk must issue notices to the exposed population. In 1992, the Legislature amended the program to further require facilities whose TAC emissions are deemed to pose a significant health risk to implement risk management plans to reduce the associated health risks. This program is implemented at the local level with state oversight.

Administering Agency: SMAQMD, with CARB oversight.

CEC and CARB Memorandum of Understanding

Authority: CA Pub. Res. Code § 25523(a); 20 CCR §1752, 1752.5, 2300-2309, and Div. 2, Chap. 5, Art. 1, Appendix B, Part (k)

Purpose: Establishes requirements in the CEC's decision-making process on an application for certification that assures protection of environmental quality.

Administering Agency: California Energy Commission.

Public Nuisance

Authority: H&SC § 41700

Purpose: Prohibits the discharge from a facility of air pollutants that cause injury, detriment, nuisance, or annoyance to the public, or which endanger the comfort, repose, health, or safety of the public, or that damage business or property.

Administering Agency: SMAQMD, with CARB oversight.

2.1.2.3 Local LORS

When the state's air pollution statutes were reorganized in the mid-1960s, local APCDs were required to be established in each county of the state. There are three different types of districts: county, regional, and unified. In addition, special air quality management districts (AQMDs), with more comprehensive authority over non-vehicular sources as well as transportation and other regional planning responsibilities, have been established by the Legislature for several regions in California, including the SMAQMD. AQMDs have principal responsibility for developing plans for meeting the state and federal AAQS; for developing control measures for nonvehicular sources of air pollution necessary to achieve and maintain both state and federal air quality standards; for implementing permit programs established for the construction, modification, and operation of sources of air pollution; for enforcing air pollution statutes and regulations governing nonvehicular sources; and for developing employer-based trip reduction programs.

Sacramento Metropolitan Air Quality Management District Air Quality Plan

Authority: H&SC §40914

Purpose: The SMAQMD plan defines the proposed strategies, including stationary source control measures and new source review rules, whose implementation will attain the state AAQS. The air quality plans also demonstrate a five-percent annual reduction in emissions of nonattainment pollutants in the SMAQMD. The relevant stationary source control measures and new source review requirements are discussed with SMAQMD Rules and Regulations.

Administering Agency: SMAQMD, with CARB oversight.

SMAQMD Rule 201 – General Permit Requirements

Authority: H&SC §40000 et seq., H&SC §40400 et seq.

Purpose and Requirements: Rule 201 establishes an orderly procedure for the review of new and modified sources of air pollution through the issuance of permits. Rule 201 specifies that any facility installing nonexempt equipment that causes or controls the emission of air pollutants must first obtain a Permit to Construct from the SMAQMD.

Administering Agency: SMAQMD, with EPA Region IX and CARB oversight.

SMAQMD Preconstruction Review for Criteria Pollutants

Authority: H&SC §40000 et seq., H&SC §40400 et seq.

SMAQMD has two separate preconstruction review programs for new or modified sources of criteria pollutant emissions:

- Rule 202 (New Source Review) combines the federal and state NSR requirements into a single rule. Rule 202 establishes pre-construction requirements for new or modified facilities to ensure that operation of such facilities does not interfere with progress towards the attainment of AAQS without unnecessarily restricting economic growth.
- Rule 203 (Prevention of Significant Deterioration) implements the PSD requirements of the federal Clean Air Act for attainment pollutants (i.e., NO₂, SO₂, CO). Rule 203 establishes pre-construction review requirements for new or modified facilities to ensure that operation of such facilities does not significantly deteriorate air quality in attainment areas while maintaining a margin for future growth. The PSD requirements apply on a pollutant-specific basis to any project that is a new major stationary source or a major modification to an existing major stationary source. The PSD regulations define a facility with the potential to emit 100 tons per year (tpy) or more of NO_x, SO_x, or CO as a major stationary source. NO_x, SO_x, and CO emissions from a modified major source are subject to PSD if the cumulative emission increase exceeds 40 tpy for NO_x or SO_x or 100 tpy for CO.

A facility can be subject to more than one of these preconstruction review programs depending on the type of criteria pollutants and criteria pollutant precursors they will emit.

Preconstruction Air Quality Monitoring

SMAQMD may, at its discretion, require preconstruction ambient air quality monitoring. Preconstruction monitoring data must be gathered over a one-year period to characterize local ambient air quality. SMAQMD may approve a shorter monitoring period of maximum anticipated ambient concentration.

Best Available Control Technology (BACT)

BACT must be applied to any new or modified emissions unit that 1) results in a quarterly increase in criteria pollutant emissions, and 2) the daily potential of the emissions unit to emit meets or exceeds 10 lb/day for VOC, NO_x, SO_x, or PM₁₀, or 550 lb/day for CO. The SMAQMD defines BACT as the following:

- The most effective emission control device, emission limit, or technique which has been required for a source or source category unless the limitations have not been demonstrated to be achievable in practice; or

- Any control device or technique determined to be technologically feasible and cost-effective.

Under no circumstances shall a BACT determination be less stringent than the emission control required by any applicable federal, state, or AQMD laws, rules, or regulations.

Emission Offsets

For a new or modified facility, whether the project triggers the emission offset requirement is based on comparing the potential emissions from the new/modified facility with the NSR regulation offset trigger levels. The offset trigger levels are summarized in Table 2-1. If a project's potential emissions exceed one or more of the offset trigger levels, offsets are required for that pollutant. Depending on the distance between the proposed new/modified project and the source of the emission offsets, the amount of required emission reduction credits (ERCs) is calculated using an offset ratio that ranges from 1.3:1 to 1.5:1 for VOC and NO_x and 1.0:1 to 1.5:1 for SO_x, PM₁₀, and CO.

TABLE 2-1: EMISSION OFFSET TRIGGER LEVELS

Pollutant	Offset Trigger Level (lbs/quarter)
VOC	5,000
CO	49,500
NO _x	5,000
SO _x	13,650
PM ₁₀	7,500

Air Quality Impact Analysis

Under the NSR regulations, an air quality dispersion analysis may be required, using an approved dispersion model, to ensure that the new/modified facility will not prevent or interfere with the attainment or maintenance of any applicable ambient air quality standard.

An air quality dispersion analysis must also be conducted, using an approved dispersion model, to evaluate impacts on ambient air quality of significant PSD increases of NO_x and SO_x emissions from any new or modified major stationary source. Project emissions must not cause an exceedance of any AAQS and the increase in ambient air concentrations must not exceed the allowable increments shown in Table 2-2.

TABLE 2-2: PSD CLASS II INCREMENTS

Pollutant	Averaging Period	Allowable Increment (µg/m ³)
NO ₂	Annual	25
SO ₂	3-Hour	512
	24-Hour	91
	Annual	20

µg/m³ = micrograms per cubic meter

Protection of Class I Areas

A modeling analysis is required to assess the impacts of project emissions on visibility in nearby Class I areas if the increase in NO_x and PM₁₀ emissions exceeds 40 tpy or 15 tpy, respectively. The increase in ambient air quality concentrations for the PSD attainment pollutants (i.e., NO_x and SO_x) within the nearest Class I area must also be characterized if there is a significant emission increase associated with the new or modified major source.

Visibility, Soils, and Vegetation Impacts

Impairment to visibility, soils, and vegetation resulting from NO_x or SO_x emissions, as well as associated commercial, residential, industrial, and other growth must be analyzed for projects triggering PSD. Cumulative impacts to local ambient air quality must also be analyzed.

Administering Agency: SMAQMD, with EPA Region IX and CARB oversight.

SMAQMD – New Source Review of Toxic Air Contaminants

Authority: H&SC §41700 et seq.

Purpose and Requirements: Under the Health and Safety Code, SMAQMD is given broad authority to protect the public from the discharge of air contaminants that endanger health and safety. Consequently, the SMAQMD developed risk assessment guidelines for new and modified stationary sources¹. These guidelines establish allowable risks for new or modified sources of TAC emissions. The guidelines specify limits for maximum individual cancer risk (MICR), cancer burden, and noncarcinogenic acute and chronic hazard indices (HIs) for new or modified sources of TAC emissions. While the guidelines do not specifically require the application of best available control technology for toxics (T-BACT) to any new or modified source that emits carcinogenic TACs, the rule relaxes the MICR risk threshold when T-BACT is applied. The health risks resulting from project emissions, as demonstrated with a risk assessment, must not exceed the risk thresholds shown in Table 2-3.

TABLE 2-3: HEALTH RISK THRESHOLDS

Risk Criteria	Risk Threshold
MICR (w/o T-BACT)	1 x 10 ⁻⁶
MICR (w/ T-BACT)	10 x 10 ⁻⁶
Chronic HI	1
Acute HI	1

Administering Agency: SMAQMD.

SMAQMD Rule 207 – Federal Operating Permit

Authority: H&SC §40000 et seq., H&SC §40400 et seq.

¹ SMAQMD Supplemental Risk Assessment Guidelines for New and Modified Stationary Sources, December 2000.

Purpose and Requirements: Rule 207 (Title V Permits) provides for the issuance of federal operating permits that contain all federally enforceable requirements for stationary sources as mandated by Title V of the Clean Air Act. Rule 207 requires major facilities and acid rain facilities undergoing modifications to obtain an operating permit containing the federally enforceable requirements mandated by Title V of the Clean Air Act. A new stationary source must submit a complete Title V application within 12 months of commencing operation, and a modified source (minor modification) must submit a Title V modification application after receiving its preconstruction permit but before commencing operation. The application submitted to the SMAQMD must present all information necessary to evaluate the subject facility and determine the applicability of all regulatory requirements.

Administering Agency: SMAQMD, with EPA Region IX oversight.

SMAQMD Rule 208 – Acid Rain Permit

Authority: H&SC §40000 et seq., H&SC §40400 et seq.

Purpose and Requirements: Rule 208 (Acid Rain) provides for the issuance of acid rain permits in accordance with Title IV of the Clean Air Act. Rule 208 requires a subject facility to hold emissions allowances for SO_x, and to monitor SO_x, NO_x, and CO₂ emissions and exhaust gas flow rates (monitoring of operating parameters such as fuel use and fuel constituents is an allowable alternative to exhaust continuous emissions monitoring (CEM) systems).

Administering Agency: SMAQMD, with EPA Region IX oversight.

SMAQMD Regulation 8 – Standards of Performance for New Stationary Sources

Authority: H&SC §40000 et seq., H&SC §40400 et seq.

Purpose and Requirements: Regulation 8 (New Source Performance Standards) incorporates, by reference, the provisions of Part 60, Chapter I, Title 40 of the Code of Federal Regulations. Regulation 8 requires compliance with federal Standards of Performance for Stationary Gas Turbines.

Subpart KKKK (Standards of Performance for Stationary Gas Turbines) applies to gas turbines modified after February 18, 2005 with a heat input at peak load equal to or greater than 10 million British thermal units per hour (MMBtu/hr) (higher heating value). “Modification” is defined in 40 CFR 60.14 as any physical or operational change that results in an increase in the emission rate (in units of lb/hr or kg/hr) of any pollutant to which the standard applies. The NSPS limits SO₂ emissions to either 0.060 pounds per million BTUs (lb/MMBtu) or 0.90 pounds per megawatt-hour (lb/MWh) effective January 1, 2008. The NSPS also limits NO_x emissions from modified turbines rated between 50 MMBtu/hr and 850 MMBtu/hr firing natural gas to either 42 ppm at 15 percent or 2.0 lb/MWh.

Administering Agency: SMAQMD, with EPA Region IX oversight.

SMAQMD Prohibitory Rules

Authority: H&SC §40000 et seq., H&SC §40400 et seq., indicated SMAQMD Rules

Purpose and Requirements: Relevant local prohibitory rules of the SMAQMD include the following:

- Rule 401 – Ringlemann Chart: Establishes limits for visible emissions from stationary sources. Rule 401 prohibits visible emissions as dark or darker than Ringelmann No. 1 for periods greater than three minutes in any hour.
- Rule 402 – Nuisance: Prohibits the discharge from a facility of air pollutants that cause injury, detriment, nuisance, or annoyance to the public, or that damage business or property.
- Rule 403 – Fugitive Dust: Establishes requirements to reduce the amount of PM entrained in the ambient air as a result of man-made fugitive dust sources. Rule 403 requires the implementation of best available control measures to minimize fugitive dust emissions and prohibits visible dust emissions beyond the property line.
- Rule 404 – Particulate Matter: Limits the discharge to the atmosphere from any source of particulate matter in excess of 0.1 grains per dry standard cubic foot.
- Rule 413 – Stationary Gas Turbines: Establishes limits for emissions of NO_x from stationary gas turbines. For natural gas-fired gas turbines equipped with SCR systems, Rule 413 limits NO_x emissions to 9 ppm at 15 percent O₂.
- Rule 420 – Sulfur Content of Fuels: Rule 420 limits the sulfur content of natural gas to 50 grains per 100 cubic feet.

2.1.3 Overview of Air Quality Standards

The US EPA has established NAAQS for O₃, NO₂, CO, SO₂, (PM₁₀), PM_{2.5}, and airborne Pb. Areas with air pollution levels above these standards can be considered “nonattainment areas” subject to planning and pollution control requirements that are more stringent than standard requirements.

In addition, ARB has established standards for ozone, CO, NO₂, SO₂, sulfates, PM₁₀, airborne Pb, H₂S, and vinyl chloride at levels designed to protect the most sensitive members of the population, particularly children, the elderly, and people who suffer from lung or heart diseases.

Both state and national air quality standards consist of two parts: an allowable concentration of a pollutant and an averaging time over which the concentration is to be measured. Allowable concentrations are based on the results of studies of the effects of the pollutants on human health, crops and vegetation, and, in some cases, damage to paint and other materials. The averaging times are based on whether the damage caused by the pollutant is more likely to occur during exposures to a high concentration for a short time (1 hour, for instance), or to a relatively lower average concentration over a longer period (8 hours, 24 hours, or 1 month). For some pollutants there is more than one air quality standard, reflecting both the short-term and long-term effects. Table 2-4 presents the National and California AAQS for selected pollutants. The California standards are generally set at concentrations much lower than the federal standards and in some cases have shorter averaging periods.

TABLE 2-4: AMBIENT AIR QUALITY STANDARDS

Pollutant	Averaging Time	California ^a	National
Ozone	1 hour	0.09 ppm	0.12 ppm
	8 hours	0.070 ppm	0.08 ppm (3-year average of annual 4th-highest daily maximum)
Carbon Monoxide	8 hours	9.0 ppm	9 ppm
	1 hour	20 ppm	35 ppm
Nitrogen Dioxide	Annual Average	0.030 ppm ^b	0.053 ppm
	1 hour	0.18 ppm ^b	-
Sulfur Dioxide	Annual Average	-	0.03 ppm
	24 hours	0.04 ppm	0.14 ppm
	3 hours	-	0.5 ppm ^c
	1 hour	0.25 ppm	-
Suspended Particulate Matter (10 microns)	Annual Arithmetic Mean	20 µg/m ³	-
	24 hours	50 µg/m ³	150 µg/m ³
Suspended Particulate Matter (2.5 microns)	Annual Arithmetic Mean	12 µg/m ³	15 µg/m ³ (3-year average)
	24 hours	-	35 µg/m ³ (3-year average of 98 th percentiles)
Sulfates	24 hours	25 µg/m ³	-
Lead	30 days	1.5 µg/m ³	-
	Calendar Quarter	-	1.5 µg/m ³
Hydrogen Sulfide	1-hour	0.03 ppm	-
Vinyl Chloride	24-hours	0.010 ppm	-
Visibility Reducing Particles	8-hour (10am to 6pm PST)	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70%.	-

Notes:

^a ppm = parts per million by volume; µg/m³ = micrograms per cubic meter

^b California NO₂ standards currently pending approval by California Office of Administrative Law.

^c Federal 3-hour SO₂ standard based on secondary impacts.

EPA's new NAAQS for ozone and fine particulate matter went into effect on September 16, 1997. For ozone, the previous one-hour standard of 0.12 ppm was replaced by an eight-hour average standard at a level of 0.08 ppm. Compliance with this standard will be based on the three-year average of the annual 4th-highest daily maximum eight-hour average concentration measured at each monitor within an area.

The NAAQS for particulates were revised in several respects. First, compliance with the current 24-hour PM₁₀ standard will now be based on the 99th percentile of 24-hour concentrations at each monitor within an area. Two new PM_{2.5} standards were added: a standard of 15 micrograms per cubic meter ($\mu\text{g}/\text{m}^3$), based on the three-year average of annual arithmetic means from single or multiple monitors (as available); and a standard of 35 $\mu\text{g}/\text{m}^3$, based on the three-year average of the 98th percentile of 24-hour average concentrations at each monitor within an area.

2.1.4 Environmental Consequences

This section presents the project's environmental consequences, including emissions and ambient air quality impacts from construction and operation of the facility, and demonstrates compliance with applicable LORS.

The facility is subject to SMAQMD Rules 201, 202, and 203, which contain the SMAQMD's NSR and PSD permitting requirements.

The SMAQMD NSR regulation requires that BACT be used, emission offsets be provided, and an air quality impact analysis be performed for projects triggering these requirements. Ambient air quality impact analyses have previously been conducted for the SCA plant to satisfy SMAQMD and EPA requirements, as well as CEC requirements, for criteria pollutants (NO₂, CO, PM₁₀, and SO₂), noncriteria pollutants, and construction impacts. The applicability of the SMAQMD regulatory requirements and facility compliance with these requirements is based on facility emission levels and ambient air quality impact analyses.

Maximum pollutant emission rates and ambient impacts of the project have been evaluated to determine compliance with SMAQMD and federal regulations. The modified emissions sources include three gas turbines, two combined cycle turbines with duct burners and heat recovery steam generators (HRSGs) and one simple cycle peaking power turbine. This analysis is based on the modification of all three gas turbine engines from a "PA or PC (peaker)" model to the "PC Sprint/EFS" model.

Maximum annual emissions will decrease for NO_x and will not change for PM₁₀ and VOC. Annual emissions will increase for CO and SO_x. Maximum annual emissions are based on operation of the two combined cycle turbines at maximum firing rates for the entire year, while the simple cycle turbine emissions are based on operation at maximum firing rates for 5,731 hours per year. Annual emissions include the expected maximum number of startups that may occur in a year. Each gas turbine startup will result in transient emission rates until steady-state operation for the gas turbine and emission control systems is achieved; these startup emissions are not expected to change as a result of the gas turbine upgrade project.

The criteria pollutant ambient impact analysis uses maximum ambient impacts for each affected pollutant and averaging period from the original SCA Commission Decision (Docket No. 93-AFC-2) and ratios these impacts to reflect the new SO_x and CO emission rates, and shows that these revised impacts are far below any applicable ambient air quality standards. The following sections describe the emission changes from the turbines, the analyses of ambient impacts, and the evaluation of facility compliance with the applicable air quality regulations.

2.1.3.1 Construction Phase Impacts

Construction emissions from the turbine upgrade project are expected to be negligible. Fugitive dust emission from the asphalt, engineered compacted gravel surface, and concrete plant surface will be negligible, and construction equipment usage will be minimal, especially when compared to original plant construction. Therefore, no analysis of ambient impacts from construction activities was performed.

2.1.3.2 Operational Impacts

Emissions from Modified Equipment

As discussed previously in this document, the modified equipment consists of three GE LM6000 PC Sprint/EFS combustion gas turbines, each rated at 50 MW (nominal). Natural gas will be the only fuel used at the facility.

Fuel combustion results in the formation of NO_x, SO_x, unburned hydrocarbons (VOC), PM₁₀, and CO. The combustion gas turbines will be equipped with water injection that minimizes the formation of NO_x. The PC Sprint combustors reduce NO_x emissions from the turbine to about 25 ppm at 15% oxygen, whereas the previous PA design resulted in NO_x emissions of about 42 ppm at 15% oxygen. The project also includes selective catalytic reduction (SCR) control systems to further reduce NO_x emissions. Because natural gas is a clean-burning fuel, there will be minimal formation of combustion PM₁₀ and SO_x.

Criteria Pollutant Emissions. The gas turbine emission rates have been estimated from vendor data, facility design criteria, and established emission calculation procedures. Emission rates for the combustion gas turbines before and after the turbine upgrade are shown in Tables 2-5, 2-6, 2-7, and 2-8.

TABLE 2-5: EMISSIONS FROM EXISTING COMBUSTION TURBINES

Pollutant	ppmvd @ 15% O ₂	Lb/MMBtu	Lbs/Hr (per gas turbine)
NO _x	5	0.0183	8.22
SO _x	—	0.0006	0.27
CO	—	0.0073	3.30
VOC	—	0.0026	1.18
PM ₁₀	—	0.0056	2.50

Basis: SMAQMD Permit to Operate issued 11/08/2001 and based on 450 MMBtu/hr turbine firing rate.

TABLE 2-6: EMISSIONS FROM EXISTING COMBUSTION TURBINES WITH DUCT FIRING

Pollutant	ppmvd @ 15% O ₂	Lb/MMBtu	Lbs/Hr (per gas turbine)
NO _x	5	0.0182	9.72
SO _x	—	0.0006	0.32
CO	—	0.0079	4.20
VOC	—	0.0034	1.80
PM ₁₀	—	0.0062	3.30

Basis: SMAQMD Permit to Operate issued 11/08/2001 and based on 450 MMBtu/hr turbine firing rate and 83.2 MMBtu/hr duct burner firing rate.

TABLE 2-7: EMISSIONS FROM MODIFIED COMBUSTION TURBINES

Pollutant	ppmvd @ 15% O ₂	Lb/MMBtu ^e	lbs/hr (per turbine) ^e
NO _x ^a	2.5	0.0092	4.60
SO _x ^d	—	0.0006	0.30
CO ^b	6.0	0.0132	6.73
VOC ^c	—	0.0024	1.18
PM ₁₀ ^c	—	0.0050	2.50

Basis: ^a NO_x emissions based on 25 ppm from the turbine and 90 percent control across the SCR catalyst.

^b CO emissions reflect BACT for water-injected gas turbines, though project does not trigger CO

BACT.

^c PM₁₀ and VOC emission rates are unchanged from current SCA Permit to Operate.

^d SO_x emissions based on same emission factor as current SCA Permit to Operate.

^e All factors reflect maximum PC Sprint firing rate of 500 MMBtu/hr

TABLE 2-8: EMISSIONS FROM MODIFIED COMBUSTION TURBINES WITH DUCT FIRING

Pollutant	ppmvd @ 15% O ₂	Lb/MMBtu ^e	lbs/hr (per turbine and DB) ^e
NO _x ^a	2.5	0.0092	5.37
SO _x ^d	—	0.0006	0.35
CO ^b	6.0	0.0132	7.85
VOC ^c	—	0.0031	1.80
PM ₁₀ ^c	—	0.0057	3.30

Basis: ^a NO_x emissions based on 25 ppm from the turbine and 90% control across the SCR catalyst.

^b CO emissions reflect BACT for water-injected gas turbines, though project does not trigger CO BACT.

^c PM₁₀ and VOC emission rates are unchanged from current SCA Permit to Operate.

^d SO_x emissions based on same emission factor as current SCA Permit to Operate.

^e All factors reflect maximum PC Sprint firing rate of 500 MMBtu/hr and 83.2 MMBtu/hr duct burner

Maximum emission rates expected to occur during a startup or shutdown are shown in Table 2-9. These emission rates are taken from the SMAQMD Final Determination of Compliance for the SCA Project dated August 19, 1994 and will not change as a result of the turbine upgrade project. VOC, PM₁₀, and SO_x emissions have not been included in this table because emissions of these pollutants will be lower during a startup period than during baseload facility operation.

TABLE 2-9: MAXIMUM TURBINE STARTUP AND SHUTDOWN EMISSION RATES (PER GAS TURBINE)^a

	NO _x	CO
Combined Cycle Startup or Shutdown, lbs/hour	21.35	16.8
Simple Cycle Startup or Shutdown, lbs/hour	14.39	9.2

^a See SCA Final DOC (8/19/94), Appendix D.

The maximum daily and annual fuel consumption rates used to calculate maximum potential hourly, daily, and annual emissions for each pollutant for combined cycle and simple cycle operation are shown in Tables 2-10 and 2-11. These are based on a maximum of 8,760 operating hours per year, per combined cycle turbine, and 4,380 hours per year of duct firing with each turbine operating at 100 percent load. Simple cycle operation is based on 5,731 hours per year of operation at 100 percent load.

TABLE 2-10: MAXIMUM COMBINED CYCLE HEAT INPUT RATES (HHV)

Period	Total Fuel Use, Two Gas Turbines		Gas Turbines, each	Duct Burners, each	
Per Hour	1,000	MMBtu/hr	500	83.2	MMBtu/hr
Per Day	24,000	MMBtu/day	12,000	1,996.8	MMBtu/day
Per Year	8,760,000	MMBtu/yr	4,380,000	364,416	MMBtu/yr

TABLE 2-11: MAXIMUM SIMPLE CYCLE HEAT INPUT RATES (HHV)

Period	Total Fuel Use	
Per Hour	500	MMBtu/hr
Per Day	12,000	MMBtu/day
Per Year	2,865,500	MMBtu/yr

Analysis of maximum emissions from the modified turbines was based on the emission rates and fuel flow rates shown in Tables 2-7 and 2-10 and the expected startup emission rates shown in Table 2-9. Maximum emissions for each period were determined by evaluating the following operating cases for hourly, daily, and annual operations.

Maximum Hourly Emissions:

- For NO_x and CO, three gas turbines in startup mode; or

- Three gas turbines at full load and two turbines duct firing at maximum capacity.

Maximum Daily Emissions:

- For NO_x and CO, each gas turbine in startup mode for 1 hour, followed by 23 hours of full load operation, with 23 hours of duct firing at the two combined cycle turbines; or
- For all other pollutants, all turbines at full load for 24 hours with 24 hours of duct firing for the two combined cycle turbines.

Maximum Annual Emissions:

- For NO_x and CO, each combined cycle gas turbine has 40 hours of startups and shutdowns per year and operates at full load for the remaining 8,720 hours; or
- For all other pollutants, each combined cycle gas turbine operates at full load for 8,760 hours per year and duct firing at each turbine occurs for 4,380 hours per year at maximum load; and
- For NO_x and CO the simple cycle gas turbine has 200 hours of startups and shutdowns per year and operates at full load for 5,531 hours per year; or
- For all other pollutants the simple cycle gas turbine operates at full load for 5,731 hours per year.

The maximum annual, daily, and hourly emissions for the modified turbines are shown in Table 2-12. Tables 2-13 and 2-14 compare these emissions to the current turbine permit emission limits.

TABLE 2-12: EMISSIONS FROM MODIFIED GAS TURBINES^a

	NO _x	SO _x	CO	VOC	PM ₁₀
Maximum Hourly Emissions (lbs/hr)					
Gas Turbine 1A ^b	5.37	0.35	7.85	1.80	3.30
Gas Turbine 1B ^b	5.37	0.35	7.85	1.80	3.30
Gas Turbine 1C ^b	4.60	0.30	6.73	1.18	2.50
Total =	15.35	1.00	22.42	4.78	9.10
Maximum Daily Emissions (lbs/day)					
Gas Turbine 1A ^c	144.9	8.4	197.3	43.2	79.2
Gas Turbine 1B ^c	144.9	8.4	197.3	43.2	79.2
Gas Turbine 1C ^c	120.3	7.2	163.9	28.3	60.0
Total =	410.0	24.0	558.4	114.7	218.4
Maximum Annual Emissions (lb/yr)					
Gas Turbine 1A ^d	42,755	2,847	64,230	12,703	25,404
Gas Turbine 1B ^d	42,755	2,847	64,230	12,703	25,404
Gas Turbine 1C ^d	27,327	1,719	39,045	6,412	14,329
Total =	112,837	7,413	167,505	31,818	65,137

^a See Appendix A for calculations.

^b Maximum hourly emissions do not include startup emissions.

^c Maximum daily emissions include startup emissions.

^d Maximum annual emissions include startup emissions and NO_x emissions based on 480 MMBtu/hr annual average firing rate (all other pollutants based on 500 MMBtu/hr firing rate).

TABLE 2-13: CURRENT SCA TURBINE EMISSION LIMITS^a

	NO _x	SO _x	CO	VOC	PM ₁₀
Maximum Hourly Emissions (lbs/hr)					
Gas Turbine 1A ^b	9.72	0.32	4.20	1.80	3.30
Gas Turbine 1B ^b	9.72	0.32	4.20	1.80	3.30
Gas Turbine 1C ^b	8.22	0.27	3.30	1.18	2.50
Total =	27.66	0.91	11.70	4.78	9.10
Maximum Daily Emissions (lbs/day)					
Gas Turbine 1A	233.0	7.7	113.4	43.2	79.2
Gas Turbine 1B	233.0	7.7	113.4	43.2	79.2
Gas Turbine 1C	203.8	6.5	85.1	28.3	60.0
Total =	669.8	21.9	311.9	114.7	218.4
Maximum Annual Emissions (lb/yr)					
Gas Turbine 1A	74,568	2,567	34,692	12,703	25,404
Gas Turbine 1B	74,568	2,567	34,692	12,703	25,404
Gas Turbine 1C	45,063	1,550	20,096	6,412	14,329
Total =	194,199	6,684	89,480	31,818	65,137

^a See Appendix A for calculations.

^b Maximum hourly emissions do not include startup emissions

TABLE 2-14: PROPOSED SCA FACILITY EMISSION CHANGES^a

	NO _x	SO _x	CO	VOC	PM ₁₀
Maximum Hourly Emissions (lbs/hr)					
Gas Turbine 1A ^b	-4.35	0.03	3.65	0	0
Gas Turbine 1B ^b	-4.35	0.03	3.65	0	0
Gas Turbine 1C ^b	-3.62	0.03	3.43	0	0
Total =	-12.31	0.09	10.72	0	0
Maximum Daily Emissions (lbs/day)					
Gas Turbine 1A	-88.1	0.7	83.9	0	0
Gas Turbine 1B	-88.1	0.7	83.9	0	0
Gas Turbine 1C	-83.5	0.7	78.8	0	0
Total =	-259.8	2.1	246.5	0	0
Maximum Annual Emissions (lb/yr)					
Gas Turbine 1A	-31,813	280	29,538	0	0
Gas Turbine 1B	-31,813	280	29,538	0	0
Gas Turbine 1C	-17,736	169	18,949	0	0
Total =	-81,362	728	78,025	0	0

^a See Appendix A for calculations.

^b Maximum hourly emissions do not include startup emissions.

Commissioning Emissions. The turbine upgrade project will require a brief commissioning period not to exceed 40 operating hours per turbine. Commissioning emissions will not exceed startup emissions for NO_x and CO as indicated above. The SCR and oxidation catalysts will be installed and operating during commissioning, but possibly not at full effectiveness. Daily and quarterly emissions will not exceed proposed permitted levels.

Greenhouse Gas Emissions. Greenhouse gas (GHG) emissions will increase as a result of the increased firing rate of the modified turbines (Note: comparative GHG emissions, however, will

decrease per unit of electricity produced due to improved efficiency). Table 2-15 lists the maximum annual increase in GHG emissions in units of CO₂ equivalents (CO₂e) based on the annual operating assumptions listed previously in this section:

**TABLE 2-15: PROPOSED SCA FACILITY GHG EMISSION INCREASES
(TONS/YEAR)^{a, b}**

	CO ₂	CH ₄	N ₂ O	Total CO ₂ e
Gas Turbine 1A	25,613	1.9	0.7	25,851
Gas Turbine 1B	25,613	1.9	0.7	25,851
Gas Turbine 1C	16,757	1.2	0.4	16,912
Total =	67,982	5.0	1.7	68,614

^a See Appendix A for calculations.

^b Based on emission factors from Climate Action Registry Power Plant Protocol (April 2005).

These increases are mitigated by a minimum 3.6 percent improvement in efficiency (heat rate) for the project. The existing turbines have a heat rate of 9,050 Btu/kW-hr (LHV, 48°F ambient) and emit 1,181 lb/MWh of CO₂e for the turbine alone in combined cycle operation (ignoring energy output of the steam turbine). The modified turbines will have a heat rate of 8,723 Btu/kW-hr (LHV, 50°F ambient) and will emit 1,138 lb/MWh of CO₂e for the turbine alone in combined cycle operation (ignoring energy output of the steam turbine). This is a worst case calculation because the increased turbine firing rate will also result in increased steam turbine generation, which is ignored here. See Appendix A for GHG heat rate calculations.

Noncriteria Pollutant Emissions. Noncriteria pollutants are compounds that have been identified as pollutants that pose a significant health hazard. Nine of these pollutants are regulated under the federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds. In addition to these nine compounds, the federal Clean Air Act lists 189 substances as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). Any pollutant that may be emitted from the original SCA project and is on the Federal New Source Review list and/or the federal Clean Air Act list was evaluated as part of the AFC.

Noncriteria pollutant emission impacts were found to be insignificant for the original SCA project. The increased firing associated with the turbine upgrade project will not increase noncriteria pollutant impacts to a level of significance. Table 2-16 shows the original project impacts, and increases these impacts by the ratio of 500/450 based on the maximum increase in firing rate. This represents a conservatively high estimate of increased risk, since it also effectively increases the duct burner impacts as well as the auxiliary boiler impacts, which are not being increased.

TABLE 2-16: ESTIMATED HEALTH RISK IMPACTS

Risk Criteria	Original SCA Project	Turbine Upgrade Project^a
Carcinogenic	8.66 x 10 ⁻⁷	9.62 x 10 ⁻⁷
Chronic HI	0.01	0.01
Acute HI	0.52	0.58

^a Turbine upgrade project health impacts based on original project impacts multiplied by the ratio of 500/450 (maximum firing rate increase associated with the project firing rate increase).

Air Quality Impact Analysis

Ambient Air Quality Impacts

The project only results in increases of CO and SO₂ emissions. The maximum ground-level impacts on ambient air quality for these pollutants, as modeled in the original SCA Project, added to maximum observed background concentrations from 2004 through 2006 (Table 2-17), resulted in impacts significantly below the applicable ambient air quality standards.

TABLE 2-17: MAXIMUM BACKGROUND CONCENTRATIONS, 2004-2006 (µG/M³)

Pollutant	Averaging Time	2004	2005	2006
SO ₂	1-Hour	21	26	21
	24-hour	5.3	5.3	8.0
	Annual	2.6	2.6	2.6
CO	1-Hour	8,340	9,140	8,570
	8-Hour	4,630	3,270	3,090

Note

All background concentrations from North Highlands – Blackfoot Way monitoring station.

Maximum ground-level impacts due to operation of the facility are shown together with the ambient air quality standards in Table 2-18. Despite the conservative assumptions used throughout the analysis, the results indicate that the modified gas turbines will not cause or contribute to violations of any state or federal SO₂ or CO air quality standards.

Consistency with Regulatory Requirements

Consistency with Federal Requirements. As discussed above, the SMAQMD has been delegated authority by EPA to implement and enforce most of the federal requirements that are applicable to the facility, including the new source performance standards and PSD permitting program. Compliance with the SMAQMD regulations ensures compliance and consistency with the corresponding federal requirements as well. The facility will also be required to comply with the federal acid rain requirements (Title IV). Since the SMAQMD has received delegation for implementing Title IV through its Title V permit program, SCA will apply to the SMAQMD for a Title V permit amendment that will include the necessary requirements for compliance with the Title IV acid rain provisions for the modified equipment.

TABLE 2-18: MODELED MAXIMUM PROJECT IMPACTS, SCA TURBINE UPGRADE PROJECT

Pollutant	Averaging Time	SCA Project Impact ^a (µg/m ³)	Upgrade Impact ^b (µg/m ³)	Background Concentrations (µg/m ³)	Total Impact (µg/m ³)	State Standard (µg/m ³)	Federal Standard (µg/m ³)
SO ₂	1-hour	0.37	0.41	26	26.4	655	–
	24-hour	0.06	0.07	8.0	8.1	105	365
	Annual	0.008	0.009	2.6	2.6	–	80
CO	1-hour	16.0	17.8	9,140	9,160	23,000	40,000
	8-hour	8.6	9.6	4,630	4,640	10,000	10,000

^a Entire facility including gas turbines/HRSGs, aux boiler, and cooling tower.

^b Assumes impacts increase by 500/450 based on increase in maximum turbine firing rate.

PSD Requirements

The PSD program requirements apply on a pollutant-specific basis to the following:

- A new major facility that will emit 100 tpy or more, if it is one of the 28 PSD source categories in the federal Clean Air Act (such as the proposed fossil-fuel fired steam energy project), or a new facility that will emit 250 tpy or more; or
- A major modification to an existing major facility that will result in net emissions increases in excess of the PSD significant emission thresholds.

The existing SCA Project has emissions limited to less than 100 tons per year for all pollutants. Therefore, the new turbine upgrade project would have to increase emissions by more than 100 tons per year in order to be subject to PSD review. As indicated above, CO emissions will increase by about 39 tons per year and SO₂ emissions will increase by less than a half ton per year. Total project emissions will remain below 100 tons per year for each pollutant. Therefore, the turbine upgrade project does not trigger PSD review.

National Emission Standards for Hazardous Air Pollutants

EPA has established a NESHAP for gas turbines (40 CFR Part 63, Subpart YYYY). This regulation applies to new or modified major sources of HAPs (as listed in Section 112 of the Clean Air Act). Because the HAP emissions for the modified Project are below the major source thresholds of 10 tpy for a single HAP and 25 tpy for any combination of HAPs, the project is exempt from the NESHAP for gas turbines. Consequently, this regulation does not apply to the project and will not be addressed further.

New Source Performance Standards

For the gas turbines, Regulation 8 (New Source Performance Standards), Subpart KKKK requires monitoring of fuel; imposes limits on the emissions of NO_x and SO_x; and requires source testing of stack emissions, process monitoring, and data collection and recordkeeping. Subpart KKKK applies to gas turbines modified after February 18, 2005 with a heat input at peak load equal to or greater

than 10 MMBtu/hr (higher heating value). “Modification” is defined in 40 CFR 60.14 as any physical or operational change that results in an increase in the emission rate (in units of lb/hr or kg/hr) of any pollutant to which the standard applies. The NSPS limits SO₂ emissions to either 0.060 lb/MMBtu or 0.90 lb/MWh effective January 1, 2008. The NSPS also limits NO_x emissions from modified turbines rated between 50 MMBtu/hr and 850 MMBtu/hr firing natural gas to either 42 ppm at 15 percent oxygen or 2.0 lb/MWh.

Since the proposed turbine upgrade increases the emissions of a pollutant (SO₂) covered by Subpart KKKK, the turbines are now subject to Subpart KKKK and not Subpart GG. However, all of the BACT limits imposed on the facility will be more stringent than the requirements of the NSPS emission limits. Monitoring and recordkeeping requirements for BACT will be more stringent than the requirements in this rule. The SCA turbine upgrade project will comply with the NSPS Subpart KKKK regulation.

2.1.3.3 Title IV and V Requirements

Rule 207 (Title V – Federal Operating Permit Program) applies to facilities that have the potential to emit more than 50 tons per year for VOC or NO_x, and 100 tons per year for CO, SO_x, or PM₁₀. As an existing Title V source under this rule, a permit application will be submitted to the SMAQMD for a Title V permit modification for the plant. The Acid Rain requirements of Rule 208 (Title IV program) are also applicable to the existing facility. As a modified Acid Rain facility, SCA will be required to update its monitoring plan to reflect any changes in turbine output. SCA will obtain any necessary permit revisions necessary under Acid Rain.

2.1.3.4 CAM Requirements

CAM requires facilities to monitor the operation and maintenance of emissions control systems and report any control system malfunctions to the appropriate regulatory agency. The CAM rule applies to emissions units with uncontrolled potential to emit levels greater than applicable major source thresholds. However, the CAM rule does not apply to the project since the facility has a Title V permit requiring the installation and operation of continuous emissions monitoring systems.

Consistency with State Requirements. State law establishes local air pollution control districts and air quality management districts with the principal responsibility for regulating emissions from stationary sources. As discussed previously, the facility is under the local jurisdiction of the SMAQMD, and compliance with SMAQMD regulations will ensure compliance with state air quality requirements.

Consistency with Local Requirements: SMAQMD. The SMAQMD has been delegated responsibility for implementing local, state, and federal air quality regulations including the NSR and PSD permitting programs in the project area. The facility is subject to SMAQMD regulations that apply to new sources of emissions, to the prohibitory regulations that specify emission standards for individual equipment categories, and to the requirements for evaluation of impacts from toxic air pollutants.

Under the regulations that govern new or modified sources of emissions, SCA is required to secure a preconstruction permit from the SMAQMD, as well as demonstrate continued compliance with regulatory limits when the facility becomes operational. The NSR/PSD preconstruction review

includes demonstrating that the facility will use BACT, providing any necessary emission offsets, demonstrating that emissions will not interfere with the attainment or maintenance of the applicable AAQS and will not exceed SMAQMD significance levels, and demonstrating that the emissions will not impair visibility in nearby Class I areas. The following sections include the evaluation of facility compliance with the applicable SMAQMD NSR/PSD requirements.

2.1.3.5 BACT

SMAQMD Rule 202 requires the gas turbines/HRSGs to be equipped with BACT for all pollutants with quarterly emissions increases, provided turbine emissions exceed certain threshold emission levels. The project results in quarterly emissions increases of SO_x and CO. However, the BACT threshold for SO_x is 10 lb/day and 550 lb/day for CO for each emissions unit, and Table 2-12 indicates that emissions from each modified gas turbine unit does not exceed 10 lb/day for SO_x or 550 lb/day for CO. Therefore, the SCA turbine upgrade project does not trigger SMAQMD BACT requirements.

Nonetheless, the project will comply with BACT for NO_x and CO based on current BACT guidance documents. Since the SMAQMD does not maintain a BACT clearinghouse listing, BACT for the applicable pollutants was determined by reviewing the San Joaquin Valley APCD BACT Clearinghouse and ARB's Guidance for Power Plant Siting and Best Available Control Technology. The gas turbines associated with the SCA project will use the BACT measures discussed below.

As an SO₂ BACT control measure, the applicant will limit the fuels burned by the gas turbines and duct burners to natural gas, a clean burning, low-sulfur fuel. Natural gas is routinely considered to be BACT for SO₂ emissions.

For the gas turbines, BACT for CO emissions will be achieved by the use of an oxidation catalyst. With this technology, the gas turbines will meet a CO limit of 6 ppmvd, corrected to 15 percent O₂ (short-term average). The San Joaquin Valley APCD BACT guidelines indicate that BACT from similar LM6000 gas turbines is an exhaust concentration not to exceed 6 ppmvd CO, corrected to 15 percent O₂. CO emissions from the modified SCA project gas turbines are consistent with this BACT requirement.

The ARB BACT guidelines for gas turbines also suggest a CO level of 6 ppmvd at 15 percent O₂ (3-hour average), based principally on the use of oxidation catalyst technology, for CO nonattainment areas. In attainment areas such as the project area, CARB has given districts the discretion to set the BACT level for CO. The applicant's proposed 6 ppm CO level (short-term average) with the use of oxidation catalyst technology is consistent with these requirements.

2.1.3.6 Offset Requirements

In addition to the BACT requirements, SMAQMD Rule 202 requires SCA to provide emission reduction credits (ERCs) for all net facility emission increases for NO_x, SO_x, CO, VOC, and PM₁₀ that exceed offset threshold levels. A comparison between the maximum expected quarterly emissions increases for the project and the SMAQMD NSR offset trigger levels is shown in Table 2-19. As shown in Table 2-19, only SO_x and CO have net emission increases, and total facility SO_x emissions are well below the offset threshold. CO is above the offset threshold, but SMAQMD Rule 202, Section 302.7 does not require offsets for CO if the maximum modeled 8-hour ambient

impact is below 500 ug/m³. Table 2-18 indicates that the maximum 8-hour CO impact from the turbine upgrade project is less than 10 ug/m³. Therefore, the turbine upgrade project does not trigger SMAQMD emission offset requirements

**TABLE 2-19: SUMMARY OF OFFSET REQUIREMENTS,
SCA TURBINE UPGRADE PROJECT**

Unit	NO _x (lbs/quarter)	CO (lbs/quarter)	SO _x (lbs/quarter)	VOC (lbs/quarter)	PM ₁₀ (lbs/quarter)
Net Increase from Gas Turbines	(20,503)	19,667	184	0	0
Total Facility Emissions	29,625	50,078 ^a	1,944	8,472	17,603
Offset Trigger Level	5,000	49,500	13,650	5,000	7,500
Offsets Required?	No	No ^a	No	No	No

Notes:

^a CO emissions are not subject to offsets pursuant to SMAQMD Rule 202, Section 302.7, because the project air quality modeling analysis shows that the maximum 8-hour CO impact is much less than 500 ug/m³.

2.1.3.7 Modeling Analysis

Rules 202 and 203 require project denial if PM₁₀, NO_x, SO_x, or CO air quality modeling results indicate emissions will interfere with the attainment or maintenance of the applicable AAQS. The modeling analyses presented above shows that facility emissions will not interfere with the attainment or maintenance of the applicable air quality standards.

2.1.3.8 General Prohibitory Rules

The general prohibitory rules of the SMAQMD applicable to the facility and the determination of compliance follow.

Rule 401 (Visible Emissions). Any visible emissions from the Project will not be darker than No.1 when compared to a Ringlemann Chart for any period(s) aggregating three minutes in any hour. Because the facility will burn clean fuels, the opacity standard of not greater than 20 percent for a period or periods aggregating three minutes will not be exceeded.

Rule 402 (Public Nuisance). Rule 402 prohibits the discharge of air pollutants that cause injury, detriment, nuisance, or annoyance to the public, or that damage business or property. The facility will emit insignificant quantities of odorous or visible substances; therefore, the facility will comply with this regulation.

Rule 403 (Fugitive Dust). Rule 403 establishes requirements to reduce the amount of PM entrained in the ambient air as a result of man-made fugitive dust sources. Since construction will occur on concrete and asphalt surfaces, fugitive dust emissions will not trigger the requirements of this rule. During the operation of the facility, there will be minimal fugitive dust emissions, and the facility will comply with the regulation.

Rule 404 (Particulate Matter). Because the gas turbines will use only natural gas, the gas turbine emissions will be well below the 0.1 gr/dscf particulate matter limit of the rule, and the facility will comply with the regulation.

Rule 406 (Specific Contaminants). Because the gas turbines will use only natural gas, plant emission rates will be well below the SO_x and particulate matter limits of the rule, and the facility will comply with the regulation.

Rule 413 (Stationary Gas Turbines). Because the gas turbines will meet 2.5 ppm at 15% for NO_x, the gas turbine NO_x emission levels will be well below the 9 ppm at 15 percent O₂ NO_x limit of the rule, and the facility will comply with the regulation.

Rule 420 (Sulfur Content of Fuels). Rule 420 limits the sulfur content of natural gas to 50 grains per 100 cubic feet. The natural gas used by the facility will have a sulfur content below the limit of this rule.

Air Toxic Rules

SMAQMD Risk Assessment Guidelines for New and Modified Stationary Sources. These guidelines establish allowable risks for new or modified sources of TAC emissions. The guidelines specify limits for maximum individual cancer risk (MICR) and noncarcinogenic acute and chronic hazard indices (HIs) for new or modified sources of TAC emissions. As shown above, the proposed Project will not cause toxic air pollutant impacts greater than the guideline significance levels.

2.1.3.9 Cumulative Impacts

The potential cumulative impacts of the original project and other nearby projects were adequately considered in the original SCA AFC. The modification project results in a small increase in SO_x emissions, and an increase in CO emissions. These increases result in an insignificant contribution to background emissions levels that are less than half of the ambient air quality standards, as indicated in the above ambient air quality analysis. Therefore, no further cumulative impacts analysis will be conducted.

2.1.4 Mitigation Measures

Mitigation has been provided for all applicable emissions increases from the original project in the form of offsets, as required under SMAQMD regulations. Only SO_x and CO emissions increase as a result of the modification project. CO emissions are not required to be fully mitigated under SMAQMD regulations or CEC practice. PM₁₀ emissions were used in the original application to mitigate SO_x emission increases, and the small increase in SO_x emissions continue to be fully mitigated as indicated in Table 2-20.

2.1.5 Conclusion

Therefore, in addition to complying with current LORS, the existing Conditions of Certification, modified to include the emission increases for SO_x and CO, and modified to include the emission reductions for NO_x, are adequate to protect the environment with respect to air quality.

TABLE 2-20: PROPOSED SCA FACILITY EMISSION MITIGATION^a

	Q1	Q2	Q3	Q4	TOTAL
Maximum Quarterly Emissions (lbs/qtr)					
PM ₁₀	8,287	8,380	8,472	8,472	33,611
SO _x	1,901	1,923	1,944	1,944	7,712
Total =	10,188	10,303	10,416	10,416	41,323
Mitigation Provided (lbs/qtr)					
Sierra Pine 1993 (PM ₁₀)	16,387	16,569	16,751	16,571	66,458
Sierra Pine 2001 (PM ₁₀)	833	842	852	852	3,379
Total =	17,220	17,411	17,603	17,603	69,837
Excess Mitigation Provided=	7,031	7,109	7,187	7,187	28,514

2.1.6 Requested Modifications to Conditions of Certification

The Sacramento Metropolitan Air Quality Management District (SMAQMD) amended Rule 411, NOx from Boilers, Process Heaters and Steam Generators, on October 27, 2005, a copy of which is attached for reference in Appendix B. With that rule amendment, boilers larger than 20 MMBtu/hr and fired on gaseous fuels became subject to a nitrogen oxides (NOx) limit of 9 ppmvd at 3% O₂ with exceptions for periods of startup and shutdown. For SCA's auxiliary boiler rated at 108.7 MMBtu/hr, Rule 411 required full compliance with the 9 ppmvd NOx limit no later than October 27, 2007. SCA determined that existing boiler equipment and operational practices were adequate to assure full compliance with amended Rule 411. As such, SCA accepted revised permit conditions from SMAQMD in the form of Permit to Operate No. 12318 (Rev03) issued April 3, 2007, a copy of which is attached for reference in Appendix C.

SCA proposes conforming amendments to Conditions of Certification for consistency with SMAQMD's permit to operate the auxiliary boiler. Current CEC Condition AQ-15 allows NOx emissions up to 30 ppmvd when the boiler is operated at low load conditions, defined as below 25%. Amended Rule 411 prohibits NOx above 9 ppmvd from the SCA auxiliary boiler, regardless of boiler load. Rule 411 recognizes that 9 ppmvd NOx is not achievable during boiler startup and shutdown periods. Hence, SCA proposes to add an exception for startup and shutdown periods to the Conditions of Certification. All boiler mass emission limits on a pound per hour and per day bases remain unchanged from the current Conditions of Certification.

Since Rule 411 affects some of the same conditions associated with the P&G upgrade project, SCA is proposing to modify the conditions that will incorporate changes associated with Rule 411 at this time. Therefore, SCA requests that the following conditions, applicable to the (1) P&G upgrade project and (2) Rule 411 auxiliary boilers be modified as follows. Strikeout denotes deletions and bold/underline denotes additions to the condition language; commentary is provided in italic type:

POTENTIAL ENVIRONMENTAL IMPACTS

- AQ-10 Emissions at the SCA Cogeneration facility, on a pound per hour basis, shall not exceed the following limits averaged over a three-hour period, not including startups **and shutdowns** as defined in conditions **AQ-16, AQ-22,** and **AQ-24**.

Pollutant	Units	CTG + Duct Burner (each)	Simple Cycle CTG	Auxiliary Boiler	Cooling Tower
NOx	lb/hr	9.72 5.37	8.22 4.60	1.15	
CO	lb/hr	4.27 7.85	3.3 6.73	7.12	
ROC	lb/hr	1.8	1.18	0.41	
SOx	lb/hr	0.32 0.35	0.27 0.30	0.08	
PM10	lb/hr	3.3	2.5	0.54	0.29

~~The CO emissions from the combustion turbines were taken at a different temperature scenario which represented a worst case continuous operation condition.~~

The ~~District~~**SMAQMD**, in agreement with the applicant, may choose to decrease the above hourly emission limits to correspond to the source test results pursuant to condition 38.

Note: the rationale for including “shutdowns” is that Rule 411 requires a NOx limit of 9 ppmvd regardless of boiler load, but provides exception for periods of startup and shutdown. The proposed definitions of boiler startup and shutdown conform to Rule 411.

- AQ-11 Emissions at the SCA Cogeneration facility, ~~from the following equipment listed below,~~ on a pound per calendar **day** basis, shall not exceed the following limits.

Pollutant	Units	Combined Cycle CTG with Supp. Fuel	Simple Cycle CTG	Cooling Tower	Auxiliary Boiler	Total Emissions
NOx	lb/day	233.3 144.9	203.8 120.3		27.6	697.3 437.7
CO	lb/day	443.4 197.3	85.4 163.9		170.8	482.7 729.3
ROC	lb/day	43.2	28.3		9.8	124.5
SOx	lb/day	7.7 8.4	6.5 7.2		1.8	23.7 25.8
PM10	lb/day	79.2	60	7	13.1	238.5

The ~~District~~**SMAQMD**, in agreement with the applicant, may choose to decrease the above daily emission limits to correspond to the source test results pursuant to condition 38.

- AQ-12 Emissions at the entire SCA Cogeneration facility shall not exceed the following limits on a quarterly basis.

Quarter	Unit	NO _x	CO	ROC	SO _x	PM ₁₀
Qtr 1	lb/qtr	49,051 28,981	29,758 48,990	8,287	1,722 1,901	17,220
Qtr 2	lb/qtr	49,590 29,303	30,082 49,534	8,380	1,741 1,923	17,411
Qtr 3	lb/qtr	50,128 29,625	30,407 50,078	8,472	1,760 1,944	17,603
Qtr 4	lb/qtr	50,128 29,625	30,407 50,078	8,472	1,760 1,944	17,603

The ~~District~~ **SMAQMD**, in agreement with the applicant, may choose to decrease the above ~~daily~~ **quarterly** emission limits to correspond to the source test results pursuant to condition 38.

- AQ-13 The combined cycle combustion turbines and their associated duct burner HRSGs shall not emit more than ~~52.5~~ **52.5** ppmvd nitrogen oxides at 15 percent O₂ each, averaged over any consecutive three hour period, excluding start-ups as defined in Condition 22.

- AQ-14 The simple cycle combustion turbine shall not emit more than ~~52.5~~ **52.5** ppmvd nitrogen oxides at 15 percent O₂, averaged over any consecutive three hour period, excluding start-ups as defined in Condition 24.

- ~~AQ-15 The auxiliary boiler shall not emit more than 30 ppmvd nitrogen oxides at 3% O₂ averaged over any consecutive three hour period for any load below 25 percent.~~

Note: the rational for this change is the provisions of AQ-15 conflict with the NO_x limitations in SMAQMD Rule 411 The SMAQMD amended Rule 411, NO_x from Boilers, Process Heaters and Steam Generators, on October 27, 2005 (Appendix B). With that rule amendment, boilers larger than 20 MMBtu/hr and fired on gaseous fuels became subject to a nitrogen oxides (NO_x) limit of 9 ppmvd at 3% O₂ with exceptions for periods of startup and shutdown. For SCA's auxiliary boiler rated at 108.7 MMBtu/hr, Rule 411 required full compliance with the 9 ppmvd NO_x limit no later than October 27, 2007. SCA determined that existing boiler equipment and operational practices were adequate to assure full compliance with amended Rule 411. As such, SCA accepted revised permit conditions from SMAQMD in the form of Permit to Operate No. 12318(Rev03) issued April 3, 2007 (Appendix C).

- AQ-16 The auxiliary boiler shall not emit more than 9 ppmvd nitrogen oxides at 3% O₂ averaged over any consecutive three hour period ~~any load equal to or greater than 25 percent~~ **except during periods of startup and shutdown. Startup is defined as the period of time, not to exceed two hours, in which the auxiliary boiler is brought to its operating temperature and pressure immediately after a period in which the gas flow is shut off for a continuous period of 30 minutes or longer.**

Shutdown is defined as the period of time, not to exceed two hours, in which the auxiliary boiler is cooled from its normal operating temperature.

Note: the rationale for this change is that Rule 411 requires a NO_x limit of 9 ppmvd regardless of boiler load, but provides exception for periods of startup and shutdown. The proposed definitions of boiler startup and shutdown conform to Rule 411.

AQ-50 Emissions shall be minimized to the maximum extent feasible during the commissioning period. Conditions 50 through 55 shall apply during the commissioning period.

AQ-51 The commissioning activities are defined as, but are not limited to, all testing, adjustment, tuning and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the gas turbines and heat recovery steam generators.

AQ-52 Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the gas turbine is first fired, whichever occurs first. The commissioning period shall terminate when the plant has completed initial performance testing and is available for commercial operation.

AQ-53 At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturer and the construction contractor, the combustors of this unit shall be tuned to minimize emissions.

AQ-54 Emission rates during the commissioning period shall not exceed any of the following: NO_x – 21.4 lb/hr; CO – 16.8 lb/hr. The NO_x concentration limits in Conditions AQ-13 and AQ-14 shall not apply during the commissioning period. All other hourly, daily, and quarterly emission limits shall remain effective during the commissioning period.

AQ-55 During the commissioning period, compliance with the NO_x and CO emission limits in Condition 54 shall be demonstrated through the use of properly operated and maintained continuous emissions monitors and recorders.

2.2 Public Health

The 1994 Commission Decision noted that the primary hazards to public health would result from criteria air pollutants described and modeled in the air quality section. The Commission Decision presented cancer risk modeling based on emissions and determined that the project impacts would be mitigated through conditions implemented under Air Quality. Therefore, no additional Conditions of Certification were implemented for public health. Implementation of the LM6000 Upgrade is expected to reduce net emissions of NO_x and will result in insignificant impacts to public health (see Table 2-16).

Based on this analysis, no additional impacts could be identified to public health and no additional Conditions of Certification are recommended.

2.3 Waste Generation

Construction of the LM6000 upgrade would produce relatively small amounts of waste consisting of waste steel, waste weld rod, wooden packing material and cribbing, small containers of coating, waste lubricants, typical domestic trash, and sanitary waste.

Most of the waste produced has value as recycled scrap and, therefore, with the exception of domestic trash and sanitary waste, most of the materials will be sold for recycling as scrap. Domestic trash will be removed from the site at least weekly for disposal by one of several available Sacramento-area waste management companies. Sanitary waste facilities (porta-potties) will be rented from and serviced by local vendors.

Because the quantities of waste generated by construction will be small, implementation of the existing conditions would be adequate to prevent adverse impacts from waste-generation impacts.

2.4 Noise

The original 1994 Commission Decision noted that there would be some intrusive noise impacts during project construction but that these would be temporary and limited to 6 a.m. to 8 p.m. on weekdays and 7 a.m. to 6 p.m. on weekends. Construction of the upgrade will not generate any unusual noises over those typical for operation and maintenance of the plant. Activities needed for the upgrade are the same as those used for periodic enclosure dismantling and turbine removal for maintenance. Noise from the removal and shipping would be similar to normal noise levels and unlikely to be noticeable by the property owners or tenants in the surrounding industrial area.

The Commission further determined that the operation would not result in significant impacts and that Conditions of Certification adopted as part of the project would reduce project related noise to the maximum extent possible. With respect to operation, the SPRINT/EFS upgrade reportedly will produce a quieter exhaust flow with less vibration in downstream components than an unmodified LM6000PA (GE press release, May 6, 2006). Conditions were applied that required notification of potentially affected parties, establishment of a noise complaint phone number and procedure, and preconstruction noise survey to identify equipment that could produce elevated noise. Implementation of the existing conditions would be adequate to prevent adverse impacts from noise impacts.

2.5 Water Resources

The 1994 Commission Decision described and analyzed the project's projected water use, including the adequacy and reliability of the water supply, the potential for flooding as well as the adequacy of proposed waste treatment and disposal methods. The Commission Decision noted that the project would be supplied with City of Sacramento (City) water diverted from the lower American River and treated at the Fairbairn Water Treatment Plant (WTP). The city provided a "will serve" letter indicating it would supply up to 2,500 acre-feet per year (AFY) to the project. The interconnected nature of the City's water distribution system allows water to be delivered from either the

Sacramento or American rivers, with reliable capacity of 235 million gallons per day or 263,329 AFY. The Decision noted that withdrawal of 2,500 AFY from the Fairbairn WTP would not result in any perceptible decrease in lower American River flows.

The project currently uses water for drinking water, sanitary uses (washing and toilets) and for cooling and condensing steam, and sprayed into the combustion gases for NO_x control. The three turbines currently operating use approximately 922 acre feet per year, of which 82 percent or 756 acre-feet is used for cooling and 18 percent or 168 acre-feet is used for NO_x control.

For the proposed upgrades, there is a small increase in evaporative cooling in the cooling tower from an increase in capacity of approximately 3 MW resulting from the PA to PC upgrade. No additional evaporative cooling in the cooling tower is required for the additional 5 MW of capacity resulting from the Sprint water injection. Any evaporative cooling effect in the compressor section resulting from the power augmentation water is lost as the water is converted to steam in the hot section of the burner and power turbine. The benefit of power augmentation water use is distinguishable by the fact that the resulting mass flow rate increase in the compressor and hot section of the turbine provides added mechanical forces to act upon the turbine blades, thereby producing more torque. The torque on the shaft produces greater amperage at a constant generator shaft speed, which in turn produces more output power. There is no economically or technically suitable alternative for water used in the power augmentation process.

After the LM6000 upgrade, drinking water and sanitary uses will not change. The annual project use for all three cogeneration units will increase to approximately 989 acre-feet, of which 76 percent will be for cooling and 23.7 percent or 234 acre-feet will be for power augmentation and NO_x control. The current Conditions of Certification allow 2,111 acre-feet per year of water use. The project would remain within this existing use and would require no change in entitlements or agreements for water supply.

The 1994 Commission Decision made findings and conclusions concerning project impacts to water supplies. Finding No. 5 specified “the proposed project’s use of surface water, by itself, and cumulatively in combination with the Campbell cogeneration project will not adversely impact local surface water resources.”

Since the Commission has already determined that the allocation of 2,500 acre-feet per year of surface water would not adversely affect surface water resources, and since the project water use would remain well within the current Condition of Certification limits, the project upgrade is determined not to cause any adverse impacts to surface water resources.

Conditions of Certification imposed by the Commission required the project obtain a National Pollutant Discharge elimination System (NPDES) permit for discharge of wastewater, and that the project would include diked areas to contain 100 percent of the tank spill capacity plus a 24-hour precipitation event. Neither of the existing conditions imposed requirements on surface water use within the existing allocation.

The project would cause no adverse impacts to surface water or wastewater.

2.6 Soil Resources

The P&G Facility was originally constructed on an undeveloped lot in an area where there were undeveloped parcels adjacent to the facility. The area where the upgrade would take place is now either paved or has engineered and compacted gravel surfacing. Adjacent areas have also been largely developed and paved since 1993. The proposed modification will be implemented on paved areas, with the addition of three small concrete pads on existing engineered and compacted surfacing, away from any open soil areas. Therefore the proposed modification would have no effect on soils or soil resources. No additional conditions are necessary to protect soil resources.

2.7 Biological Resources

The potential biological impacts of upgrading the LM6000s were analyzed by reviewing the project description and identifying actions that would potentially affect biological resources. Consultants working for the District reviewed the existing 1994 Commission Decision to identify previously existing resources and mitigation measure that were implemented to minimize impacts.

The 1994 Commission Decision was primarily concerned with converting open grassland habitat into industrial habitat. The LM6000 fleet upgrade would change the equipment within an existing industrial area and would not convert any habitat from natural condition. For this reason, no direct impacts to biological resources or wetlands from habitat changes could be identified.

Changes in the amount of fuel burned and quantity of emissions could contribute incrementally to air quality degradation or generation of greenhouse gases that would contribute to regional or global habitat changes. However, according to the air quality analysis provided earlier, the fleet upgrade would result in a net reduction of NO_x emissions and lower greenhouse gas emissions per megawatt-hour, and therefore incrementally reduce the quantity of air quality emissions. Overall, the LM6000 upgrade is expected to have an immeasurable effect on biological habitat and regional values, and is modeled to have a slightly beneficial effect in reducing the generation of NO_x and greenhouse gases.

Therefore, in addition to complying with current laws and regulations, the existing Conditions of Certification are considered adequate to protect the environment with respect to biological resources.

2.8 Socioeconomics

The Commission Decision specified that because the Sacramento area is a large urbanized area, that impacts of the project to the population or housing market would be negligible. The proposed project changes would requires fewer than 20 construction workers, and have an even smaller impact on local housing and population. The findings of the decision and applied conditions remain adequate to avoid adverse impacts to socioeconomic resources.

2.9 Land Use

The proposed project change does not affect the uses or conditions of use presented in the Land Use analysis and Findings of the Commission Decision. The proposed LM6000 fleet upgrade is proposed to occur within the developed area and structures of the existing P&G Facility. Short-term construction-related impacts would involve additional truck traffic and equipment movement. No

adverse land-use impacts are expected during the upgrade, and no changes in post-construction land use are anticipated. The conditions imposed in the Commission Decision will continue to adequately protect land use resources.

2.10 Visual Resources

When the P&G Facility was originally constructed, the visual nature of the area was mixed industrial with some open space. That area has now been largely converted to industrial activity and additional industrial activities are consistent with existing uses. As described in this Petition's description section, the activities necessary to complete the upgrade are largely the same as a typical maintenance cycle and would not change any existing conditions for visual resources at the site.

The proposed LM6000 modification would have no effects on visual and aesthetic resources

2.11 Cultural, Paleontological, and Historic Resources

The potential cultural resources impacts of upgrading the LM6000s were analyzed by reviewing the original project description and identifying actions that would potentially affect cultural resources.

The 1994 Commission Decision was primarily concerned with converting rural and industrial lands, some of which had not been previously excavated into industrial habitat. The LM6000 fleet upgrade would change the equipment within an existing industrial area and would not convert any land from an undisturbed condition. There would be no excavation or construction that would require undisturbed areas to be excavated. The operation of the plant would continue essentially as currently permitted, causing no identifiable effect to cultural resources. For this reason, no direct or indirect impacts to cultural, paleontological or historical resources could be identified.

Therefore, in addition to complying with current laws and regulations, the existing Conditions of Certification are considered adequate to protect the environment with respect to cultural, paleontological, and historic resources.

2.12 Traffic and Transportation

The 1994 Commission Decision primarily addressed increases in construction traffic but determined that they would not cause adverse effects on local arterials. Traffic in the project vicinity has increased in the years between 1994 and 2007 with increasing regional population, but during this time some large facilities such as the Sacramento Army Depot and Procter & Gamble facility have either shut down or greatly reduced operations. As a result, traffic conditions in the area remain acceptable. The LM6000 modification will require no more than an additional 20 construction workers and a consequent increase in traffic during construction. Turbine transport will require a standard flatbed truck delivery during each removal and replacement cycle. This amount of activity is not expected to adversely affect existing traffic conditions.

Conditions of Certification in the AFC describe compliance with trucking, transportation, oversize permit and hazardous material shipping requirements, as well as considering the combined effects of construction at the project concurrent with the Line 700 A and B pipeline construction. The existing

Conditions of Certification would remain applicable to the LM6000 modification and are considered adequate to protect the environment with respect to traffic and transportation.

2.13 Hazardous Materials Management

The 1994 Commission Decision described the analysis of potential risks to the public and identified that natural gas was the only component that had the potential to cause significant impact. The 1994 Commission Decision noted that the project would have limited amounts of ammonium hydroxide, sulfuric acid and similar materials on site to support construction. In addition, modeling was run to determine the potential off-site consequences of accidental spills of aqueous ammonia, hydrochloric acid or hydrazine. The Commission Decision also noted that natural gas could be an explosive hazard. The Decision required a Safety Management Plan, spill containment structures, requirements for reportable quantities, Emergency Response Plan and Risk Management Plans that are all part of the project's continuing operations.

Removal and replacement of the LM6000 is expected to use small amounts of cleaners and lubricants in addition to those already present on site, but conditions are generally the same as during operation, and no new hazardous materials are anticipated. The same plans, containment structures and procedures implemented to prevent accidental releases of dangerous quantities remain active on the project site and would remain so throughout the LM6000 modification.

Since no substantial new hazardous materials will be used to implement the project, the existing Conditions of Certification are considered adequate to protect the environment from hazardous material use or releases. The conditions imposed in the 1994 Commission Decision are adequate to prevent significant adverse impacts to hazardous materials.

2.14 Geological Hazards and Resources

The LM6000 upgrade would not change the footprint of the project area in any manner, nor require excavation or disturbance of the existing ground. No new buildings would be constructed; therefore, no potential impacts to geological resources or from geological hazards could be identified.

Compliance with the existing Conditions of Certification is considered adequate to protect the environment with respect to geological resources.

2.15 Paleontological Resources Results

The LM6000 upgrade would not change the footprint of the project area in any manner, nor require excavation or disturbance of the existing soil of any kind. Therefore, no potential impacts to paleontological resources could be identified.

Compliance with the existing conditions is adequate to protect the environment with respect to paleontological resources.

The following subsections respond to specific requirements of Section 1769(a) of the CEC' Siting Regulations (Title 20, California Administrative Code, Section 1769[a]), regarding potential impacts to the facilities compliance with laws and regulations and also the potential impacts of the modification on the public and adjacent landowners.

3.1 Impacts the Modification May Have on the Facilities' Ability to Comply with Applicable Laws, Ordinances, Regulations and Standards

The project modification, as proposed, would have no adverse effect on the ability of the certified facility to comply with applicable laws, ordinances, regulations and standards (LORS) as discussed in the Air Quality section. Additionally, the project would improve the efficiency of the facility and its ability to meet environmental goals while meeting the current demand for electricity. The project would continue to operate in compliance with all applicable LORS.

3.2 How the Modification Affects the Public

With implementation of the conditions modifications proposed, the upgrade would have no immediately detectable affect on the public. The project would contribute slightly to producing additional power with less NO_x and lower greenhouse gases per MWh and, therefore, would result in a small benefit. However, this change, while measurable, is practically undetectable to the public.

3.3 Property Owners Potentially Affected by the Modification

No impacts to any adjacent or distant property owners could be identified. Property owners within 1,000 feet of the project are listed in Appendix D.

3.4 Potential Effect on Nearby Property Owners, the Public and Parties in the Proceedings

Activities conducted at ground level are generally not visible to residential property owners and the general public in the project area. This is because the project area is largely industrial, and the turbines are located behind locked cyclone fences. Many parts of the plant are obscured by equipment and buildings on the project area. With the exception of the medium-size cranes used to lift equipment into place and the trucks brought in to carry the turbines, it is unlikely that nearby owners or the public would see or notice any unusual activity at the project site.

Turbine removal and replacement could cause some temporary increase in noise related to operation of the crane, removal of metal parts of the turbine enclosure or truck movement. However, this activity is expected to be brief and of a magnitude that is less than typical ambient noise associated with other plant activities.

Turbine removal and replacement involves the same amount of weight and materials associated with typical maintenance activities and should not be detectable to any of the public as an unusual activity.

The project would not change the footprint, visible conditions, noise or any other visible part of the project operation and thus is expected to have no detectable effect on nearby property owners.

4.0 REFERENCES

California Energy Commission. 1994. Commission Decision; Application for Certification of the Sacramento Cogeneration Authority's Procter & Gamble Cogeneration Project. Docket NO. 93-AFC-2. November 1994.

Sacramento Metropolitan Air Quality Management District (SMAQMD). 2004. Guide to Air Quality Assessment in Sacramento County.

APPENDIX A

Calculations Supporting Emissions Estimates

SCA Emissions Calculations

BASE LOAD TURBINE				
MMBtu/hr =		500		
F-Factor =		8710		
Pollutant	ppmc	MW	Calc lb/hr	Calc lb/MMBtu
NOx	2.5	46	4.60	0.0092
CO	6	28	6.73	0.0135
VOC	1.84	16	1.18	0.0024
		lb/MMBtu		
SO2		0.00060	0.30	
PM10		0.00500	2.50	

PEAKING TURBINE		
MMBtu/hr =		500
F-Factor =		8710
Pollutant	ppmc	MW
NOx	2.5	46
CO	6	28
VOC	1.84	16
		lb/MMBtu
SO2		0.00060
PM10		0.00500

DUCT BURNER		
MMBtu/hr =		83.2
F-Factor =		8710
ppmc	MW	lb/hr
2.5	46	0.77
6	28	1.12
5.82	16	0.62
	lb/MMBtu	
	0.00060	0.05
	0.00960	0.80

Hourly Total			
Calc lb/hr	Permit lb/hr	Change lb/hr	Permit lb/MMBtu
5.37	9.72	(4.35)	0.0167
7.85	4.2	3.65	0.0072
1.80	1.8	-	0.0031
0.35	0.32	0.03	
3.30	3.3	0.00	

Hourly Total			
Calc lb/hr	Permit lb/hr	Change lb/hr	Permit lb/MMBtu
4.60	8.22	(3.62)	0.0164
6.73	3.30	3.43	0.0066
1.18	1.18	0.00	0.0024
0.30	0.27	0.03	
2.50	2.50	-	

Hourly Turbine Total			
Operation lb/hr	Permit lb/hr	Change lb/hr	Startup lb/hr
15.35	27.66	(12.31)	57.09
22.42	11.70	10.72	42.80
4.78	4.78	0.00	
1.00	0.91	0.09	
9.10	9.10	(0.00)	

Pollutant
NOx
CO
VOC
SO2
PM10

SCA Emissions Calculations

Daily Maximum					
Operation hr/day	Startup lb/hr	Startup hr/day	Calc lb/day	Permit lb/day	Change lb/day
23	21.35	1	144.9	233.0	(88.1)
23	16.8	1	197.3	113.4	83.9
24	0	0	43.2	43.2	-
24	0	0	8.4	7.7	0.7
24	0	0	79.2	79.2	(0.0)

Daily Maximum					
Operation hr/day	Startup lb/hr	Startup hr/day	Calc lb/day	Permit lb/day	Change lb/day
23	14.39	1	120.3	203.8	(83.5)
23	9.2	1	163.9	85.1	78.8
24	0	0	28.3	28.3	0.0
24	0	0	7.2	6.5	0.7
24	0	0	60.0	60	-

Daily Turbine Total					
Pollutant			Calc lb/day	Permit lb/day	Change lb/day
NOx			410.0	669.8	(259.8)
CO			558.4	311.9	246.5
VOC			114.7	114.7	0.0
SO2			24.0	21.9	2.1
PM10			218.3	218.4	(0.1)

Daily Cooling Tower				
Pollutant			Calc lb/day	Permit lb/day
NOx				
CO				
VOC				
SO2				
PM10			7.0	7.0

Daily Aux Boiler				
Pollutant			Calc lb/day	Permit lb/day
NOx			27.6	27.6
CO			170.8	170.8
VOC			9.8	9.8
SO2			1.8	1.8
PM10			13.1	13.1

Daily Plant Total				
Pollutant			Calc lb/day	Permit lb/day
NOx			437.6	697.4
CO			729.2	482.7
VOC			124.5	124.5
SO2			25.8	23.7
PM10			238.4	238.5

Annual Maximum						
Turbine hr/yr	DB hr/yr	Startup lb/hr	Startup hr/yr	Annual Avg Rate	Calc lb/yr	Permit lb/yr
8720	4380	21.35	40	480	42,755	74,568
8720	4380	16.8	40	500	64,230	34,692
8760	4380	0	0	500	13,052	12,703
8760	4380	0	0	500	2,847	2,567
8760	4380	0	0	500	25,398	25,404

Annual Maximum						
Turbine hr/yr	DB hr/yr	Startup lb/hr	Startup hr/yr	Annual Avg Rate	Calc lb/yr	Permit lb/yr
5531	0	14.39	200	480	27,327	45,063
5531	0	9.2	200	500	39,045	20,096
5731	0	0	0	500	6,763	6,412
5731	0	0	0	500	1,719	1,550
5731	0	0	0	500	14,328	14,329

Annual Turbine Total						
Pollutant					Calc lb/yr	Permit lb/yr
NOx					112,837	194,199
CO					167,505	89,480
VOC					32,867	31,818
SO2					7,413	6,684
PM10					65,124	65,137

Annual Cooling Tower						
Pollutant					Calc lb/yr	Permit lb/yr
NOx						
CO						
VOC						
SO2						
PM10					2,567	2,567

Annual Aux Boiler						
Pollutant					Calc lb/yr	Permit lb/yr
NOx					4,697	4,697
CO					31,175	31,175
VOC					1,793	1,793
SO2					299	299
PM10					2,135	2,135

Annual Plant Total						
Pollutant					Calc lb/yr	Permit lb/yr
NOx					117,534	198,896
CO					198,680	120,655
VOC					34,660	33,611
SO2					7,712	6,983
PM10					69,826	69,839

SCA Emissions Calculations

Revised Quarterly Limits						
Pollutant		Q1	Q2	Q3	Q4	Total
NOx		28,981	29,303	29,625	29,625	117,534
CO		48,990	49,534	50,078	50,078	198,680
VOC						
SO2		1,901	1,923	1,944	1,944	7,712
PM10						

SCA GHG Emissions Increase

BASE LOAD TURBINE				
MMBtu/hr =		50	Increase	
Pollutant	kg/MMBtu	lb/hr	GWP	CO2e lb/hr
CO2	53.05	5,848	1	5,848
CH4	0.003901	0.4	23	10
N2O	0.001361	0.2	296	44

PEAKING TURBINE				
MMBtu/hr =		50	Increase	
Pollutant	kg/MMBtu	lb/hr	GWP	CO2e lb/hr
CO2	53.05	5,848	1	5,848
CH4	0.003901	0.4	23	10
N2O	0.001361	0.2	296	44

DUCT BURNER		
MMBtu/hr =		0 Increase
kg/MMBtu	GWP	CO2e lb/hr
53.05	1	-
0.003901	23	-
0.001361	296	-

Combined Cycle Annual Maximum		
Turbine hr/yr	ton/yr	CO2e ton/yr
8760	25,613	25,613
8760	1.9	43
8760	0.7	195
		25,851

Peaking Turbine Annual Maximum		
Turbine hr/yr	ton/yr	CO2e ton/yr
5731	16,757	16,757
5731	1.2	28
5731	0.4	127
		16,912

Emission Factors - California Climate Action Registry Power Reporting Protocol (April 2005)

Annual Turbine Total		
Pollutant		CO2e ton/yr
CO2	67,982	67,982
CH4	5.0	115
N2O	1.7	516
Total =	67,989	68,614

SCA Improvement in GHG Emission Rate

Original PA Turbine			
MMBtu/hr =		424.8 (48F Ambient Case)	
Gross MWh =		42.47	CO2e
Pollutant	kg/MMBtu	GWP	lb/hr
CO2	53.05	1	49,680
CH4	0.003901	23	84
N2O	0.001361	296	377
		Total =	50,141
		lb/MWh =	1,181

New PC Sprint Turbine			
MMBtu/hr =		477.6 (50F Ambient Case)	
Gross MWh =		49.541	CO2e
Pollutant	kg/MMBtu	GWP	lb/hr
CO2	53.05	1	55,852
CH4	0.003901	23	94
N2O	0.001361	296	424
		Total =	56,370
		lb/MWh =	1,138
		% Decrease =	3.62%

Emission Factors - California Climate Action Registry Power Reporting Protocol (April 2005)

Global Warming Potential (GWP) - California Climate Action Registry Power Reporting Protocol (April 2005)



Performance By: **CANONJA**
Project Info: **SMUD P&G - LM6000PC SPRINT Performance - Water Injected**

Engine: LM6000 PC-SPRINT w/ VIGV
Deck Info: G01250 - 8f2.scp
Generator: BDAX 290ERT 60Hz, 13.8kV, 0.9PF (14839)
Fuel: Gas Fuel #10-1, 19000 Btu/lb,LHV

Date: 06/26/2007
Time: 10:37:35 PM
Version: 3.5.11

Case #	100	101	102	103	104	105	106	107	108
Ambient Conditions									
Dry Bulb, °F	30.0	40.0	50.0	60.0	70.0	80.0	90.0	100.0	110.0
Wet Bulb, °F	22.8	30.2	37.5	44.6	51.5	58.3	65.0	71.8	78.5
RH, %	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Altitude, ft	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Ambient Pressure, psia	14.669	14.669	14.669	14.669	14.669	14.669	14.669	14.669	14.669
Engine Inlet									
Comp Inlet Temp, °F	30.0	40.0	50.0	60.0	70.0	80.0	90.0	100.0	110.0
RH, %	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Conditioning	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE	NONE
Tons or kBtu/hr	0	0	0	0	0	0	0	0	0
Pressure Losses									
Inlet Loss, inH2O	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
Volute Loss, inH2O	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Exhaust Loss, inH2O	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
kW, Gen Terms									
Est. Btu/kW-hr, LHV	8642	8691	8723	8778	8833	8910	9065	9215	9314
Fuel Flow									
MMBtu/hr, LHV	430.9	432.6	432.1	420.1	407.3	392.8	367.6	343.3	323.6
lb/hr	22681	22770	22745	22112	21436	20672	19345	18069	17033
NOx Control									
	Water	Water	Water	Water	Water	Water	Water	Water	Water
Water Injection									
lb/hr	23015	23766	21533	20425	19619	18677	16694	14757	13170
Temperature, °F	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
SPRINT									
lb/hr	HPC	HPC	LPC	LPC	LPC	LPC	LPC	LPC	LPC
	3795	3795	8794	9566	9411	9070	8681	8216	7348
Control Parameters									
HP Speed, RPM	10349	10456	10443	10476	10508	10521	10505	10498	10497
LP Speed, RPM	3600	3600	3600	3600	3600	3600	3600	3600	3600
PS3 - CDP, psi	468.8	463.4	460.1	449.0	438.0	425.9	404.0	382.8	363.9
T3CRF - CDT, °F	965	991	976	982	991	999	999	999	999
T48IN, °R	2005	2038	2038	2038	2038	2037	2027	2017	2014
T48IN, °F	1545	1578	1578	1578	1578	1577	1567	1557	1555
Exhaust Parameters									
Temperature, °F	822.8	849.2	852.2	858.8	865.4	872.3	879.7	886.3	897.5
lb/sec	308.2	302.0	299.2	291.9	284.7	277.0	263.4	250.1	237.8
lb/hr	1109374	1087076	1077042	1050737	1025050	997096	948158	900371	855927
Energy, Btu/s- Ref 0 °R	101570	101932	101543	99683	97820	95736	91598	87496	84027
Energy, Btu/s- Ref T2 °F	63853	64142	63235	61538	59864	58089	55117	52192	49816
Cp, Btu/lb-R	0.2743	0.2759	0.2769	0.2774	0.2778	0.2782	0.2785	0.2789	0.2797
Emissions (NOT FOR USE IN ENVIRONMENTAL PERMITS)									
NOx ppmvd Ref 15% O2	25	25	25	25	25	25	25	25	25
NOx as NO2, lb/hr	44	44	44	42	41	40	37	35	33
CO ppmvd Ref 15% O2	48	40	27	22	18	15	11	8	6
CO, lb/hr	50.34	42.04	28.13	22.84	18.26	14.07	9.77	6.48	4.35
CO2, lb/hr	57281.29	57508.45	57450.80	55862.13	54161.07	52241.27	48899.82	45683.77	43071.65
HC ppmvd Ref 15% O2	6	5	3	2	2	2	2	2	2
HC, lb/hr	3.72	2.71	1.81	1.38	1.29	1.24	1.16	1.08	1.02
SOX as SO2, lb/hr	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

SCA

10/05/93

LM6000 Combustion Turbine and HRSG Exhaust Gas
Calculations for Combined Cycle Operation
Gas Fired, w/o Duct Firing

	BASE LOAD	75% LOAD	50% LOAD
Chiller	ON	ON	ON
Ambient Temp/Relative Humidity	(Note 1)	(Note 1)	(Note 1)
Compressor Inlet Temperature, F	48	48	48
Compr. Inlet Relative Humidity, %	100	100	100
CTG Load	100%	75%	50%
CTG Gross Power, kW (per unit)	42,470	31,770	21,040
CTG Gross Heat Rate, Btu/kWh (LHV)	9,050	9,210	10,305
CTG Heat Input, MBtu/h (LHV)	384.35	292.60	216.82
Supplemental Heat Input, MBtu/h (LHV)	0.00	0.00	0.00
Supplemental Fuel Flow, lb/h	0	0	0
CTG Fuel Flow, lb/h	20,230	15,401	11,412
Air Flow, lb/h	1,000,170	870,739	725,388
Injection flow, lb/h	15,300	9,480	5,600
CTG Exhaust Flow, lb/h (per unit)	1,035,700	895,600	742,400
CTG Exhaust Temperature, F	845	789	756
Atmospheric Pressure, psia	14.675	14.675	14.675
Emissions (per unit at CTG exhaust flange)			
NOx, ppmvd @15% O2	40	40	40
NOx, lb/h as NO2	61	47	35
CO, ppmvd	15	33	81
CO, ppmvd @15% O2	15	37	103
CO, lb/h	14	27	55
SO2, lb/h (0.00% S in fuel)	0	0	0
UHC, ppmvd	11	11	13
UHC, ppmvw	10	10	12
UHC, ppmvd @15% O2	11	12	16
UHC, lb/h as CH4	6	5	5
ROC, lb/h as 20% of UHC as CH4	1.2	1.0	1.0
Particulates, lb/h (maximum)	2.5	2.5	2.5
CTG Exhaust Analysis (Volume Basis - Wet)			
CO2	3.13%	2.81%	2.52%
H2O	9.00%	7.75%	6.75%
O2	13.65%	14.48%	15.19%
N2	73.33%	74.07%	74.64%
Ar	0.89%	0.89%	0.90%
SO2	0.00%	0.00%	0.00%
Total	100.00%	100.00%	100.00%
Emissions (per unit at HRSG exit)			
NOx, ppmvd @15% O2 w/o SCR	40.0	40.0	40.0
NOx, lb/h as NO2 w/o SCR	61	47	35
NOx, ppmvd @15% O2 w/ SCR	5.0	5.0	5.0
NOx, lb/h as NO2 w/ SCR	7.7	5.9	4.4
CO, ppmvd w/o Catalyst	15.0	33.0	81.0
CO, ppmvd @ 15% O2	15.0	37.3	103.2
CO, lb/h w/o Catalyst	14	27	55
CO, Catalyst Effectiveness	90.0%	90.0%	90.0%
CO, ppmvd w/ Catalyst	1.5	3.3	8.1
CO, ppmvd @ 15% O2 w/ Catalyst	1.5	3.7	10.3
CO, lb/h w/ Catalyst	1.4	2.7	5.5
SO2, lb/h (0.00% S in fuel)	0.0	0.0	0.0
UHC, ppmvd (10.0% reduction)	9.9	9.8	11.6
UHC, ppmvw (10.0% reduction)	9.0	9.0	10.8
UHC, ppmvd @15% O2	9.9	11.0	14.8
UHC, lb/h as CH4	5.3	4.6	4.5
ROC, ppmvd as 20% of UHC @ 15% O2	2.0	2.2	3.0
ROC, lb/h as 20% of UHC as CH4	1.1	0.9	0.9
Particulates, lb/h (maximum)	2.5	2.5	2.5
Particulates, grains/scf (dry @ 12% CO2)	0.001	0.002	0.002
Ammonia, ppmvd	10.0	10.0	10.0
Ammonia, lb/h	5.7	4.4	3.3

Note 1. Compressor inlet temperature is 48 F for all
ambients above 48 F due to inlet chilling.

APPENDIX B

SMAQMD Rule 411

RULE 411, NO_x FROM BOILERS, PROCESS HEATERS AND STEAM GENERATORS**Adopted 02-02-95****(Amended 11/7/96, 01/09/97, 7/22/99, 10/27/05)****INDEX****100 GENERAL**

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100 GENERAL

101 **PURPOSE:** To limit NO_x and CO emissions from boilers, steam generators, and process heaters.

102 **APPLICABILITY:** The requirements of this Rule shall apply to units (i.e., boilers, steam generators and process heaters) fired on gaseous or nongaseous fuels with a rated heat input capacity of 1 million Btu per hour or greater.

110 **EXEMPTION - ELECTRIC UTILITY BOILERS:** The requirements of this Rule shall not apply to any unit that is exclusively used by an electric utility to generate electricity.

111 **EXEMPTION - PROCESS HEATERS, KILNS, AND FURNACES:** The requirements of this Rule shall not apply to process heaters, kilns, and furnaces where the products of combustion come into direct contact with the material to be heated.

112 **EXEMPTION - WASTE HEAT RECOVERY BOILERS:** The requirements of this Rule shall not apply to waste heat recovery boilers.

113 **EXEMPTION - LOW FUEL USAGE:**

113.1 The requirements of Sections 301 and 302 that are effective May 31, 1997, and 303 and 304 shall not apply to any unit rated at 5 million Btu per hour input or greater that uses less than 90,000 therms per year of fuel provided that the owner or operator complies with one of the requirements listed in Section 305. If the fuel usage for any unit claiming this exemption exceeds or equals 90,000 therms in any calendar year, then the unit must be operated in compliance with the applicable NO_x and CO emission limits in Sections 301 through 304. This exemption applies only to owners or operators that applied for use of this exemption on or before May 31, 1997, and received approval pursuant to Rule 201 – General Permit Requirements. Additionally, any unit exempt pursuant to this section must comply with the recordkeeping requirements in Section 502.

113.2 The requirements of Sections 301 and 302 that are effective pursuant to the applicable schedule in Section 407, shall not apply to any unit with annual usage below the applicable level in the table below. An owner or operator of a unit that is exempt pursuant to this section shall comply with Section 305.1 or 305.2. Additionally, any owner or operator claiming this exemption shall submit to the District prior to October 27, 2006 a complete application for Authority to Construct pursuant to Rule 201-GENERAL PERMIT REQUIREMENTS to establish fuel usage limitations. Any unit exempt pursuant to this section shall comply with one of the requirements listed in Section 306.2. If the annual fuel usage for any unit exceeds or equals the level specified in the table below, then the unit must comply with the requirements in Section 405. This exemption applies only to owners or operators that applied for use of this exemption on or before October 27, 2006 and received approval pursuant to Rule 201-GENERAL PERMIT REQUIREMENTS. Additionally, any unit exempt pursuant to this section must comply with the recordkeeping requirements in Section 502.

Boiler Size (mmBtu/hr)	Annual Fuel Usage (therms/yr)
1 - <2.5	40,000
≥2.5 - <5	70,000
≥5 - <100	200,000
≥100	300,000

114 **EXEMPTION – STANDING PILOT FLAME BURNER:** The NO_x emission requirements in Section 301 shall not apply to a standing pilot flame burner that is used in a load following unit to sustain low steam demand. To qualify for this exemption, the standing pilot flame

burner heat input rating shall not exceed 5 mmBtu/hr. Additionally, the NO_x emissions from the standing pilot flame shall not exceed 30 ppmvd @ 3% O₂, except for startup and shutdown periods. Any source test required by Section 403 shall include separate testing of the standing pilot flame burner for which this exemption is claimed.

200 DEFINITIONS

- 201 **ANNUAL FUEL USAGE (HEAT INPUT):** The total input of fuels burned by a unit in a calendar year, as determined from the higher heating value and cumulative annual usage of each fuel.
- 202 **BEST AVAILABLE RETROFIT CONTROL TECHNOLOGY (BARCT):** Best available retrofit control technology as defined in Section 40406 of the California Health and Safety Code is "an emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of sources." These limits are specified in Sections 301, 302, 303, and 304.
- 203 **BIOMASS:** Any solid, organic material used as a fuel source for boilers or steam generators including, but not limited to, wood, almond shells, or agricultural waste.
- 204 **BIOMASS BOILER OR BIOMASS STEAM GENERATOR:** A boiler or steam generator that burns a fuel containing biomass.
- 205 **BOILER OR STEAM GENERATOR:** Any external combustion equipment fired with any fuel used to produce hot water or steam, excluding waste heat recovery boilers.
- 206 **BRITISH THERMAL UNIT (BTU):** The amount of heat required to raise the temperature of one pound of water from 59°F to 60°F at one atmosphere.
- 207 **HEAT INPUT:** The chemical heat released due to fuel combustion in a combustion unit, using the higher heating value of the fuel. This does not include the sensible heat of incoming combustion air.
- 208 **GASEOUS FUEL:** Any fuel which is a gas at standard conditions.
- 209 **HIGH HEATING VALUE (HHV):** The total heat liberated per mass of fuel burned (Btu per pound), when fuel and dry air at standard conditions undergo complete combustion and all resultant products are brought to their standard states at standard conditions. If certification of the HHV is not provided by the third party fuel supplier, it shall be determined by one of the test methods specified in Section 501.3.
- 210 **LANDFILL GAS:** Any gas derived through any biological process from the decomposition of waste buried within a waste disposal site.
- 211 **LOAD FOLLOWING UNIT:** A unit with normal operational load fluctuations and requirements, imposed by fluctuations in the process(es) served by the unit, which exceed the operational response range of an Ultra-Low NO_x burner system(s) operating at 9 ppmv NO_x. The operator shall designate load-following units on the Permit to Operate.
- 212 **MALFUNCTION:** Any sudden and unavoidable failure of air pollution control equipment or process equipment or of a process to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunction.
- 213 **NITROGEN OXIDES (NO_x):** The sum of nitric oxide and nitrogen dioxide in the flue gas.
- 214 **NONGASEOUS FUEL:** Any fuel which is not a gas at standard conditions.

- 215 **PARTS PER MILLION BY VOLUME (PPMV):** The ratio of the number of gas molecules of a given species, or group, to the number of millions of total gas molecules.
- 216 **PROCESS HEATER:** Any unit fired with any fuel which transfers heat from combustion gases to water or process streams, including reformers as defined in Section 218. Process heater does not include any dryer in which the material being dried is in direct contact with the products of combustion, cement or lime kilns, glass melting furnaces, or smelters.
- 217 **RATED HEAT INPUT CAPACITY:** The heat input capacity in million Btu per hour specified in the nameplate of the combustion unit. If the heat input capacity on the nameplate of the unit's burner is different than the heat input capacity on the nameplate of the unit's boiler, the heat input capacity of the burner will be used to determine rated heat input capacity. If the burner or boiler has been altered or modified such that its maximum heat input capacity is different than the heat input capacity specified on the name plate, the maximum heat input capacity shall be considered as rated heat input capacity.
- 218 **REFORMER:** A furnace in which a hydrocarbon feedstock is reacted with steam over a catalyst at high temperature to form hydrogen and lesser amounts of carbon monoxide and carbon dioxide.
- 219 **RETROFIT:** Any physical change to an emissions unit necessary for reducing NO_x and CO emissions to comply with the NO_x and CO emissions limits specified in Sections 301 through 304 of this rule, including, but not limited to, burner replacement, addition of emissions control equipment, and addition of oxygen trim systems. Changes in the method of operation shall not be considered as retrofit.
- 220 **SHUTDOWN:** The period of time a unit is cooled from its normal operating temperature. The shutdown period shall be limited to two hours.
- 221 **STANDARD CONDITIONS:** For the purpose of this rule, standard conditions are 68 °F and one atmosphere.
- 222 **STARTUP:** The period of time, not to exceed two hours, in which a unit is brought to its operating temperature and pressure immediately after a period in which the gas flow is shut off for a continuous period of 30 minutes or longer.
- 223 **THERM:** One hundred thousand (100,000) Btu's.
- 224 **UNIT:** Any boiler, including steam generator, as defined in Section 204 or Section 205, or process heater, as defined in Section 216.
- 225 **WASTE HEAT RECOVERY BOILER:** A device that recovers normally unused energy and converts it to usable heat. Waste heat recovery boilers incorporating duct or supplemental burners that are designed to supply 50 percent or more of the total rated heat input capacity of the waste heat recovery boiler are not considered waste heat recovery boilers, but are considered boilers. Waste heat recovery boilers are also referred to as heat recovery steam generators.
- 226 **WOOD:** Wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to sawdust, dust from sanding, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

300 **STANDARDS**

- 301 **BARCT EMISSIONS LIMITS - GASEOUS FUEL FIRING:** Except as provided in Section 113, the NO_x and CO emissions from any unit shall not exceed the limits specified in the table below. The NO_x and CO emission limits shall be measured as parts per million by volume on a dry basis, as determined pursuant to Section 501, and corrected to three percent oxygen,

when firing on gaseous fuels.

Unit Size/Description mmBtu/hr Input	Effective May 31, 1997		Effective (See Section 407)	
	NO _x Limit ppmvd@ 3% O ₂	CO Limit ppmvd@ 3% O ₂	NO _x Limit ppmvd@3 % O ₂	CO Limit ppmvd@ 3% O ₂
Greater than or equal to 1 and less than 5	-	-	30	400
Greater than or equal to 5 and less than or equal to 20	30	400	15	400
Greater than 20	30	400	9	400
Gas Fired Reformer Furnaces	30	400	30	400
Greater than or equal to 5 and fired on landfill gas or a combination of landfill gas and natural gas	30	400	15	400
Load Following Units greater than or equal to 5 mmBtu/hr input	30	400	15	400

- 302 **BARCT EMISSIONS LIMITS - NONGASEOUS FUEL FIRING:** Except as provided in Section 113, the NO_x and CO emissions from any unit shall not exceed the limits specified in the table below. The NO_x and CO emission limits shall be measured as parts per million by volume on a dry basis, as determined pursuant to Section 501, and corrected to three percent oxygen, when firing on nongaseous fuels.

Unit Size/Description mmBtu/hr Input	Effective May 31, 1997		Effective (See Section 407)	
	NO _x Limit ppmvd@3% O ₂	CO Limit ppmvd@3% O ₂	NO _x Limit ppmvd@3% O ₂	CO Limit ppmvd@3% O ₂
Greater than or equal to 1 and less than 5	-	-	40	400
Greater than or equal to 5	40	400	40	400

- 303 **BARCT EMISSIONS LIMITS - BIOMASS FUEL FIRING**

303.1 **NO_x Emissions:** Except as provided in Section 113.1, the NO_x emissions from any unit shall not exceed 70 parts per million by volume on a dry basis, as determined pursuant to Section 501, corrected to twelve percent carbon dioxide (70 ppmvd @ 12% CO₂), when firing on biomass fuels.

303.2 **CO Emissions:** Except as provided in Section 113.1, the CO emissions from any unit shall not exceed 400 parts per million by volume on a dry basis, as determined pursuant to Section 501, corrected to twelve percent carbon dioxide (400 ppmvd @ 12% CO₂), when firing on biomass fuels.

- 304 **EMISSION LIMIT - EMERGENCY STANDBY NONGASEOUS FUEL FIRING**

304.1 **NO_x Emissions:** The NO_x emissions from any unit which normally burns gaseous fuel but burns nongaseous fuel only during emergency interruption of gaseous fuel supply by the serving utility shall not exceed 150 parts per million by volume on a dry basis as determined pursuant to Section 501, corrected to three percent oxygen (150 ppmvd @ 3% O₂), when firing on nongaseous fuel. Operation of the unit under this Section shall not exceed 168 hours per calendar year, excluding equipment and emission testing time, not exceeding 48 hours per calendar year.

- 305 **LOW FUEL USAGE:** Any unit exempted pursuant to Section 113 shall meet one of the following conditions:

- 305.1 The unit shall be operated in a manner that maintains stack-gas oxygen concentrations at less than or equal to 3.00 % by volume on a dry basis; or
- 305.2 The unit shall be tuned at least once per year by a qualified technician. If the unit is not operational for the entire calendar year, then no tune-up shall be required until re-startup of the unit. The tune-up shall be performed in accordance with the procedure described in ATTACHMENT A.

306 **EQUIPMENT REQUIREMENT - FUEL CONSUMPTION**

- 306.1 Owners or operators of units subject to the requirements of Section 304 shall install a non-resetting totalizing hour meter on each unit, or shall install a computerized tracking system that maintains a continuous daily record of hours of operation when the boiler is operated on nongaseous fuel.
- 306.2 Owners or operators of units exempt from the NO_x and CO requirements in Sections 301 through 303 pursuant to Section 113 because of low fuel usage shall:
 - a. Install a non-resetting totalizing fuel meter in the fuel line for each fuel burned. Each unit serviced by the fuel line shall have a meter installed to monitor fuel consumption. If a volumetric flow meter is installed, it must compensate for pressure and temperature using integral gauges; or
 - b. Install a non-resetting totalizing hour meter. This requirement shall apply to each unit. In this case, the fuel usage shall be calculated by multiplying the number of operating hours for the unit by the maximum fuel usage for the unit as specified by the unit manufacturer; or
 - c. Install a computerized tracking system that maintains a continuous daily record of hours of operation and/or fuel consumption rate for each fuel line. This requirement shall apply to each unit serviced by a fuel line. If only hours of operation are recorded, the fuel usage shall be calculated by multiplying the number of operating hours for the unit by the maximum fuel usage for the unit as specified by the unit manufacturer. If both hours of operation and fuel consumption rate are recorded, the actual recorded fuel consumption rate shall be integrated over the actual number of hours operated to determine total fuel usage.

400 ADMINISTRATIVE REQUIREMENTS

401 **LOW FUEL USAGE:**

- 401.1 The owner or operator of any unit claiming exemption pursuant to Section 113.1 that is required to install new fuel consumption monitoring equipment must comply with Section 306 by January 22, 2000. New fuel consumption equipment is required when one fuel meter, hour meter, or computerized tracking system serves multiple boilers and/or other equipment prior to July 22, 1999.
- 401.2 The owner or operator of any unit claiming exemption pursuant to Section 113.2 that is required to install new fuel consumption monitoring equipment must comply with Section 306 by October 27, 2007.

- 402 **REPORTING – TUNE-UP VERIFICATION:** The owner or operator of units subject to the requirements of Section 305.2 shall submit to the Air Pollution Control Officer a tune-up verification report or a verification of inactivity not less than once every calendar year for each unit.

- 403 **SOURCE TESTING FREQUENCY:** The owner or operator of units subject to the emissions limits set forth in Sections 301 through 303 shall perform emissions source testing using the test methods specified in Section 501 of this rule according to the following schedule and maintain records as provided in Section 502:

- 403.1 Except as provided in Section 405.2, an initial source test to verify compliance with the NO_x and CO emission limits effective **[See Section 407 for specific compliance dates]** listed in Sections 301 and 302 shall be conducted by the full compliance date specified in Section 407;
- 403.2 Any unit with a rated heat capacity of 20 million Btu per hour or greater shall be

tested once every calendar year.

- 403.3. Any unit with a rated heat capacity greater than or equal to 5 million Btu per hour but less than 20 million Btu per hour shall be tested once every second calendar year.
- 403.4 **Small Units:** Any unit with a rated heat capacity greater than or equal to 1 million Btu per hour input and less than 5 million Btu per hour input shall be required to be tested to verify compliance with the NO_x and CO emission limits pursuant to Section 403.1. As an alternative to testing, the owner or operator of a unit subject to the requirements of this section may use a portable analyzer as part of an Air Pollution Control Officer approved alternate emissions monitoring system. The portable analyzer shall meet the specification standards in Attachment B.
- a. At least thirty days prior to the portable analyzer test, the owner or operator shall notify the Air Pollution Control Officer of the exact date and time of the test.
- 403.5 Any unit that is equipped with a continuous emission monitoring system (CEMs) shall conduct accuracy testing using the methods specified in Section 501 of this rule once every calendar year.

404 **SOURCE TESTING PROTOCOL:**

- 404.1 **Source Tests:** At least 30 days prior to the scheduled source test date, the owner or operator of a unit subject to this rule shall submit a source test plan to the Air Pollution Control Officer. At least seven days prior to the source test, the owner or operator shall notify the Air Pollution Control Officer of the exact date and time of the source test. A final source test report, and the applicable source test observation and evaluation fee as authorized under Rule 301, shall be submitted to the Air Pollution Control Officer within 60 days following the actual source test date.
- 404.2 **Portable Analyzer:** Emission readings using a portable analyzer pursuant to Section 403.4 shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five (5) readings evenly spaced over the 15-consecutive-minute period. If the results of the portable analyzer show that the NO_x emissions from the unit exceed the allowable limits in Section 300, then the unit will be required to be source tested no later than 60 days from the date of discovering such exceedance.

405 **LOSS OF EXEMPTION:** If any unit with a Permit to Operate issued pursuant to Rule 201-GENERAL PERMIT REQUIREMENTS approving an exemption from the requirements in Sections 301 or 302 pursuant to Section 113.2 exceeds or equals the levels specified in the table in Section 113.2 in any calendar year after October 27, 2006, the owner or operator shall:

- 405.1 Maintain compliance with the requirements of Section 305 until compliance is demonstrated with Section 301 or 302; and
- 405.2 Within 12 months after the end of the calendar year during which the unit exceeded or equaled the fuel usage exemption level, conduct an initial source test and demonstrate compliance with Section 301 or 302. The unit will subsequently not qualify for exemption pursuant to Section 113.2.

406 **ADMINISTRATIVE REQUIREMENTS FOR LOAD FOLLOWING UNITS:** The owner or operator of a load following unit shall submit to the Air Pollution Control Officer with their authority to construct application the following information to demonstrate that the unit(s) qualify as load-following:

- 406.1. Technical data such as steam demand charts or other information to demonstrate the normal operational load fluctuations and requirements of the unit;
- 406.2. Technical data showing the operational response range of all reasonably available Ultra-Low NO_x burner system(s) operating at 9 ppmv NO_x; and
- 406.3. Technical data demonstrating that the unit(s) are designed and operated to optimize the use of base-loaded units in conjunction with the load-following unit(s).

- 407 **COMPLIANCE SCHEDULE:** An owner or operator of any unit subject to Section 301 or 302 on or after October 27, 2005 shall comply with this Rule in accordance with the following schedules.

407.1 Except as provided in Section 407.2 and 407.3, for units installed prior to October 27, 2005 and permit application deemed complete by the Air Pollution Control Officer prior to October 27, 2005, or installed after October 27, 2005 and permit application deemed complete prior to October 27, 2005:

Number of Units subject to Sections 301 through 304	Number of these units required to be in full compliance by October 27, 2007	Number of these units required to be in full compliance by October 27, 2008	Number of these units required to be in full compliance by October 27, 2009
1 or 2	1	2	N/A
3	1	2	3
4	2	3	4
5 or 6	2	4	6
More than 6	25% of these units	75% of these units	100% of these units

Note: Full Compliance identifies the date by which the owner shall demonstrate that each unit is in compliance with this rule.

- 407.2 For units installed after October 27, 2005 and permit application deemed complete by the Air Pollution Control Officer after October 27, 2005: date of installation.
- 407.3 For units installed prior to October 27, 2005 and permit application deemed complete by the Air Pollution Control Officer after October 27, 2005: October 27, 2006.

500 MONITORING AND RECORDS

501 TEST METHODS

501.1 GASEOUS EMISSIONS: SOURCE TEST:

- a. Compliance with the NO_x and CO emission requirements and the stack gas oxygen requirements of Sections 301 through 304 shall be determined using the test methods specified below. All emissions determinations shall be made in the as-found operating condition, except no compliance determination shall be established during unit startup as defined in Section 222, or shutdown as defined in Section 220. Tests shall be conducted while units are operating at a firing rate that is as close as physically possible to the unit's rated heat input capacity. Tests shall be conducted for three 40 minute runs. Results shall be averaged over the three test periods. Test reports shall include the operational characteristics of all flue-gas NO_x reduction equipment.
 1. Oxide of Nitrogen - ARB Method 100 or EPA Method 7E.
 2. Carbon Monoxide - ARB Method 100 or EPA Method 10.
 3. Stack Gas Oxygen - ARB Method 100 or EPA Method 3A.
 4. Carbon Dioxide - ARB Method 100 or EPA Method 3A.
- b. A scheduled source test may not be discontinued solely due to the failure of one or more runs to meet applicable standards.
- c. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of one of the following reasons, then compliance may be determined using the average of the other two runs:
 1. Forced shutdown; or
 2. Failure of an irreplaceable portion of the sampling train; or
 3. Extreme meteorological conditions presenting a hazard to the sampling team; or
 4. Other circumstances beyond the owner or operators control as determined by the Air Pollution Control Officer.

- d. A source test not conducted pursuant to the source test methods listed in Section 501.1(a) may be rejected and the test report determined to be invalid.

501.2 GASEOUS EMISSIONS: CONTINUOUS EMISSIONS MONITORING SYSTEMS

(CEMS): Compliance with NO_x emission requirements specified in Sections 301 through 304 may also be determined using CEMS. All emissions determinations shall be made in the as-found operating condition, except no compliance determination shall be established during unit startup as defined in Section 222, or shutdown as defined in Section 220. Where the unit(s) are equipped with CEMS:

- a. **General:** All CEMS must be installed according to the procedures specified in 40CFR60.13g. All CEMS shall be installed such that a representative measurement of emissions is obtained. Additional procedures for the location of CEMS found in 40CFR60 Appendix B shall be used. The data recorder for CEMS shall be in operation at all times the unit is operated.
- b. **Cycle time:** The owner or operator of any unit using a continuous emission monitoring system (CEM) shall ensure that the CEM system completes a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15 minute period.
- c. **Calibration:** Zero and span shall be checked once every 24 hours. The CEMS shall be calibrated in accordance with the manufacturer's specifications.
- d. **Averaging:** The data recorded during periods of calibration checks, zero and span adjustments shall not be included in averaging for compliance determinations. Compliance shall be determined on an hourly basis using the average of the 3 previous 1 hour average emissions concentrations. The 1-hour average emissions concentration shall be determined from at least two data points recorded by the CEMs.
- e. **Accuracy Testing:** Accuracy testing of Continuous Emission Monitoring Systems shall be conducted using a relative accuracy test audit pursuant to 40CFR60 Appendix F.

501.3 HIGH HEAT VALUE: HHV shall be determined by one of the following test methods:

- a. ASTM D 2015-85 for solid fuels; or
- b. ASTM D 240-02 or ASTM D 3282-88 for liquid hydrocarbon fuels; or
- c. ASTM D 1826-94, or ASTM D 1945-96 in conjunction with ASTM D 3588-89 for gaseous fuels.

502 RECORDKEEPING

- 502.1 The owner or operator of units subject to the requirements of Section 304 and 306.1 shall monitor and record for each unit the cumulative calendar year hours of operation on each emergency standby non-gaseous fuel.
- 502.2 The owner or operator of units exempt pursuant to Section 113 and subject to the requirements of Sections 305 and 306.2a or 306.2c for fuel consumption shall record for each unit the HHV and the calendar year gaseous and non-gaseous fuel usage.
- 502.3 The owner or operator of units exempt pursuant to Section 113 and subject to the requirements of Sections 305 and 306.2b or 306.2c for hours of operation shall record for each unit the HHV, calendar year hours of operation, and the calendar year calculated fuel usage.
- 502.4 An owner or operator subject to the requirements in Section 403.4 using a portable analyzer to verify compliance with the NO_x and CO emission limits shall keep records of the measured NO_x and CO emissions, and all data as specified in Attachment B.
- 502.5 The owner or operator of any unit subject to Section 501 of this rule shall maintain copies of all CEMS data and final source test reports as applicable.
- 502.6 Records shall be maintained on-site for a continuous 5-year period and made available for review by the Air Pollution Control Officer upon request.

Attachment A**Tuning Procedure¹****A. Equipment Tuning Procedure for Forced-Draft Boilers, Steam Generators, and Process Heaters**

Nothing in this Tuning Procedure shall be construed to require any act or omission that would result in unsafe conditions or would be in violation of any regulation or requirement established by Factory Mutual, Industrial Risk Insurers, National Fire Prevention Association, the California Department of Industrial Relations (Occupational Safety and Health Division), the Federal Occupational Safety and Health Administration, or other relevant regulations and requirements.

1. Operate the unit at the firing rate most typical of normal operation. If the unit experiences significant load variations during normal operation, operate it at its average firing rate.
2. At this firing rate, record stack gas temperature, oxygen concentration, and CO concentration (for gaseous fuels) or smoke-spot number² (for liquid fuels), and observe flame conditions after unit operation stabilizes at the firing rate selected. If the excess oxygen in the stack gas is at the lower end of the range of typical minimum values³ and if the CO emissions are low and there is no smoke, the unit is probably operating at near optimum efficiency - at this particular firing rate. However, complete the remaining portion of this procedure to determine whether still lower oxygen levels are practical.
3. Increase combustion air flow to the furnace until stack gas oxygen levels increase by one to two percent over the level measured in Step 2. As in Step 2, record the stack gas temperature, CO concentration (for gaseous fuels) or smoke-spot number (for liquid fuels), and observe flame conditions for these higher oxygen levels after boiler operation stabilizes.
4. Decrease combustion air flow until the stack gas oxygen concentration is at the level measured in Step 2. From this level gradually reduce the combustion air flow, in small increments. After each increment, record the stack gas temperature, oxygen concentration, CO concentration (for gaseous fuels) and smoke-spot number (for liquid fuels). Also, observe the flame and record any changes in its condition.
5. Continue to reduce combustion air flow stepwise, until one of these limits is reached:
 - a. Unacceptable flame conditions - such as flame impingement on furnace walls or burner parts, excessive flame carryover, or flame instability.
 - b. Stack gas CO concentrations greater than 400 ppm.
 - c. Smoking at the stack.
 - d. Equipment-related limitations - such as low wind box/furnace pressure differential, built in air-low limits, etc.

¹. This tuning procedure is based on a tune-up procedure developed by KVB, Inc. for the EPA.

². The smoke-spot number can be determined with ASTM test method D-2156 or with the Bacharach method.

³. Typical minimum oxygen levels for boilers at high firing rates are:

1. For natural gas: 0.5 - 3%
2. For liquid fuels: 2 - 4%

6. Develop an O₂ /CO curve (for gaseous fuels) or O₂/smoke curve (for liquid fuels) similar to those shown in Figures 1 and 2 using the excess oxygen and CO or smoke-spot number data obtained at each combustion air flow setting.
7. From the curves prepared in Step 6, find the stack gas oxygen levels where the CO emissions or smoke-spot number equal the following values:

Fuel	Measurement	Value
Gaseous	CO Emissions	400 ppm
#1 and #2 oils	smoke-spot number	number 1
#4 Oil	smoke-spot number	number 2
#5 Oil	smoke-spot number	number 3
Other oils	smoke-spot number	number 4

The above conditions are referred to as the CO or smoke thresholds, or as the minimum excess oxygen levels.

Compare this minimum value of excess oxygen to the expected value provided by the combustion unit manufacturer. If the minimum level found is substantially higher than the value provided by the combustion unit manufacturer, burner adjustments can probably be made to improve fuel and air mix, thereby allowing operations with less air.

8. Add 0.5 to 2.0 percent to the minimum excess oxygen level found in Step 7 and reset burner controls to operate automatically at this higher stack gas oxygen level. This margin above the minimum oxygen level accounts for fuel variations, variations in atmospheric conditions, load changes, and nonrepeatability or play in automatic controls.
9. If the load of the combustion unit varies significantly during normal operation, repeat Steps 1-8 for firing rates that represent the upper and lower limits of the range of the load. Because control adjustments at one firing rate may affect conditions at other firing rates, it may not be possible to establish the optimum excess oxygen level at all firing rates. If this is the case, choose the burner control settings that give best performance over the range of firing rates. If one firing rate predominates, setting should optimize conditions at the rate.
10. Verify that the new settings can accommodate the sudden load changes that may occur in daily operation without adverse effects. Do this by increasing and decreasing load rapidly while observing the flame and stack. If any of the conditions in Step 5 result, reset the combustion controls to provide a slightly higher level of excess oxygen at the affected firing rates. Next, verify these new settings in a similar fashion. Then make sure that the final control settings are recorded at steady-state operating conditions for future reference.

Figure 1
Oxygen/CO Characteristic Curve

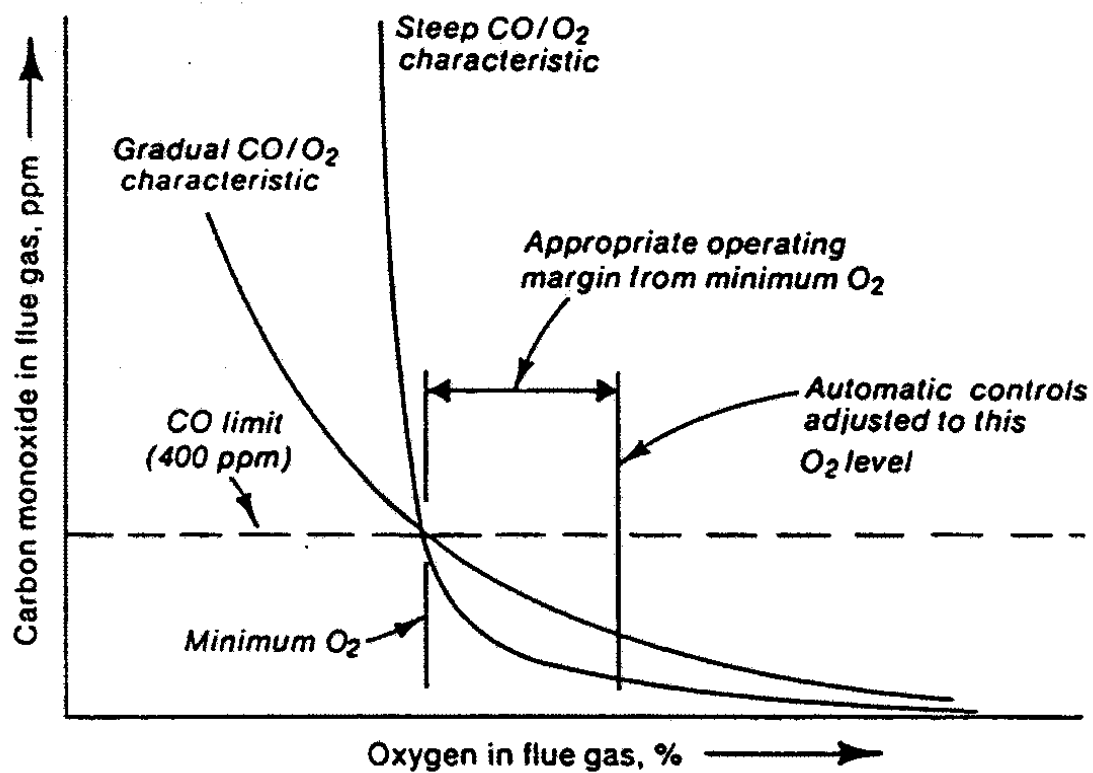
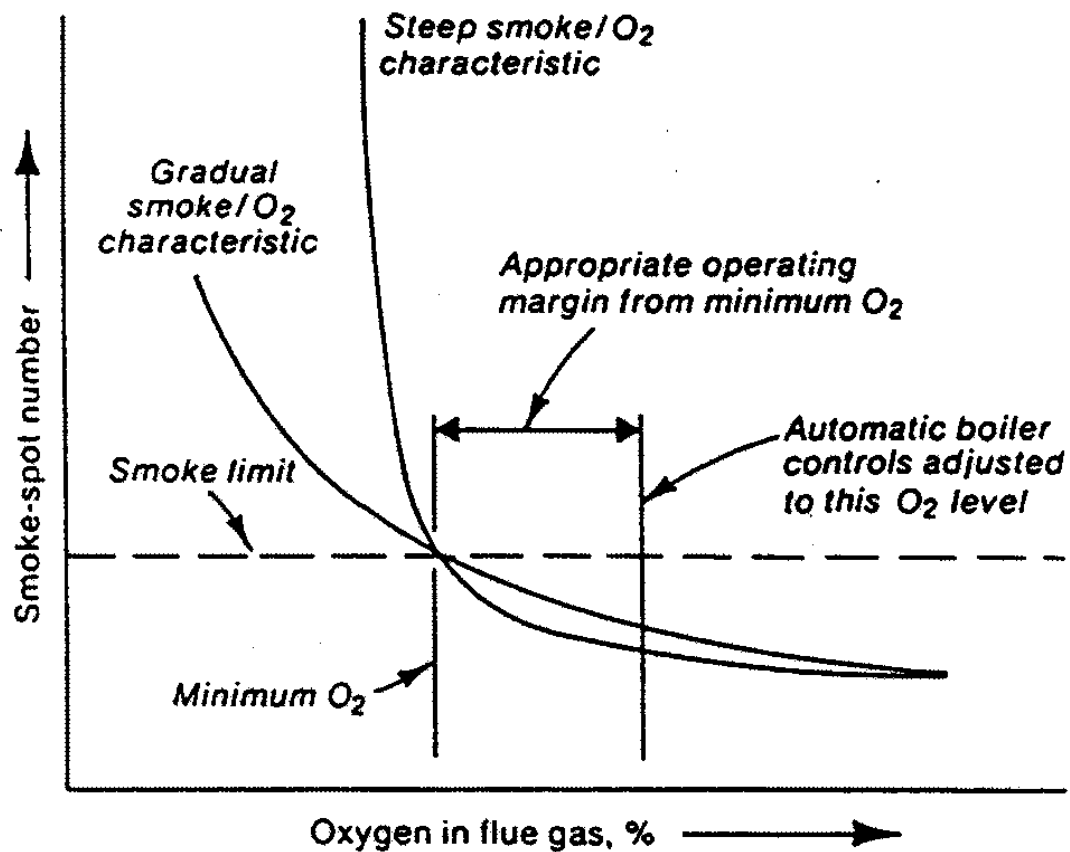


Figure 2
Oxygen/Smoke Characteristic Curve



B. Equipment Tuning Procedure for Natural Draft-Fired Boilers, Steam Generators, and Process Heaters.

Nothing in this Tuning Procedure shall be construed to require any act or omission that would result in unsafe conditions or would be in violation of any regulation or requirement established by Factory Mutual, Industrial Risk Insurers, National Fire Prevention Association, the California Department of Industrial Relations (Occupational Safety and Health Division), the Federal Occupational Safety and Health Administration, or other relevant regulations, and requirements.

1. PRELIMINARY ANALYSIS**a. CHECK THE OPERATING PRESSURE OR TEMPERATURE.**

Operate the boiler, steam generator, or heater at the lowest acceptable pressure or temperature that will satisfy the load demand. This will minimize heat and radiation losses. Determine the pressure or temperature that will be used as a basis for comparative combustion analysis before and after tuneup.

b. CHECK OPERATING HOURS.

Plan the workload so that the boiler, steam generator, or process heater operates only the minimum hours and days necessary to perform the work required. Fewer operating hours will reduce fuel use and emissions.

c. CHECK AIR SUPPLY.

Sufficient fresh air supply is essential to ensure optimum combustion and the area of air supply openings must be in compliance with applicable codes and regulations. Air openings must be kept wide open when the burner is firing and clear from restriction to flow.

d. CHECK VENT.

Proper venting is essential to assure efficient combustion. Insufficient draft or overdraft promotes hazards and inefficient burning. Check to be sure that vent is in good condition, sized properly and with no obstructions.

e. COMBUSTION ANALYSIS.

Perform an "as is" combustion analysis (CO, O₂, etc.) with a warmed up unit at high and low fire, if possible. In addition to data obtained from combustion analysis, also record the following:

ii. Inlet fuel pressure at burner (at high & low fire)

ii. Draft above draft hood or barometric damper

1) Draft hood: high, medium, and low

2) Barometric Damper: high, medium, and low

iii. Steam pressure, water temperature, or process fluid pressure or temperature entering and leaving the boiler, steam generator, or process heater.

iv. Unit rate if meter is available.

With above conditions recorded, make the following checks and corrective actions as necessary:

1. CHECKS & CORRECTIONS**a. CHECK BURNER CONDITION.**

Dirty burners or burner orifices will cause boiler, steam generator, or process heater output rate and thermal efficiency to decrease. Clean burners and burner orifices thoroughly. Also, ensure that fuel filters and moisture traps are in place, clean, and operating properly, to prevent plugging of gas orifices. Confirm proper location and orientation of burner diffuser spuds, gas canes, etc. Look for any burned-off or missing burner parts, and replace as needed.

- b. CHECK FOR CLEAN BOILER, STEAM GENERATOR, OR PROCESS HEATER TUBES & HEAT TRANSFER SURFACES.

External and internal build-up of sediment and scale on the heating surfaces creates an insulating effect that quickly reduces unit efficiency. Excessive fuel cost will result if the unit is not kept clean. Clean tube surfaces, remove scale and soot, assure proper process fluid flow and flue gas flow.

- c. CHECK WATER TREATMENT & BLOWDOWN PROGRAM.

Soft water and the proper water or process fluid treatment must be uniformly used to minimize scale and corrosion. Timely flushing and periodic blowdown must be employed to eliminate sediment and scale build-up on a boiler, steam generator or process heater.

- d. CHECK FOR STEAM, HOT WATER OR PROCESS FLUID LEAKS

Repair all leaks immediately since even small high-pressure leaks quickly lead to considerable fuel, water and steam losses. Be sure there are no leaks through the blow-off, drains, safety valve, by-pass lines or at the feed pump, if used.

2. SAFETY CHECKS

- a. Test primary and secondary low water level controls.
- b. Check operating and limit pressure and temperature controls.
- c. Check pilot safety shut off operation.
- d. Check safety valve pressure and capacity to meet boiler, steam generator or process heater requirements.
- e. Check limit safety control and spill switch.

3. ADJUSTMENTS

While taking combustion readings with a warmed up boiler, steam generator, or process heater at high fire perform checks and adjustments as follows:

- a. Adjust unit to fire at rate; record fuel manifold pressure.
- b. Adjust draft and/or fuel pressure to obtain acceptable, clean combustion at both high, medium and low fire. Carbon Monoxide (CO) value should always be below 400 parts per million (PPM) at 3% O₂. If CO is high make necessary adjustments.

Check to ensure boiler, steam generator, or process heater light offs are smooth and safe. A reduced fuel pressure test at both high and low fire should be conducted in accordance with the manufacturers instructions and maintenance manuals.

- c. Check and adjust operation of modulation controller. Ensure proper, efficient and clean combustion through range of firing rates.

When above adjustments and corrections have been made, record all data.

4. FINAL TEST

Perform a final combustion analysis with a warmed up boiler, steam generator, or process heater at high, medium and low fire, whenever possible. In addition to data from combustion analysis, also check and record:

- a. Fuel pressure at burner (High, Medium, and Low).
- b. Draft above draft hood or barometric damper (High, Medium and Low).
- c. Steam pressure or water temperature entering and leaving boiler, steam generator, or process heater.
- d. Unit rate if meter is available.

When the above checks and adjustments have been made, record data and attach combustion analysis data to boiler, steam generator, or process heater records indicating name and signature of person, title, company name, company address and date the tune-up was performed.

Attachment B**Approvable Portable Analyzer**

- A. **General:** A portable analyzer consists of a sample interface, a gas detector, and a data recorder, and is used to quantitatively analyze stack gas for one or more components. A portable analyzer for CO, O₂, or NO_x shall be considered approved by the District if it adheres to the standards that are set forth in this section, is used in accordance with the standards of this section, and is used in accordance with the manufacturer's specifications. Other portable analyzers and techniques are approvable on a case by case basis.

B. **Definitions:**

Sample interface: That portion of the portable analyzer used for one or more of the following: sample acquisition, sample transport, sample conditioning, or protection of the portable analyzer from the effects of the stack effluent.

Gas detector: That portion of the portable analyzer that senses the gas to be measured and generates an output proportional to the gas concentration.

Data recorder: A strip chart recorder, digital recorder, or any other device used for recording or displaying measurement data from the gas detector output.

Resolution: The smallest increment of output that the gas detector will provide. This value should be reported by the equipment manufacturer.

Error: The maximum standard measurement error over the measurement range. This value should be reported by the equipment manufacturer.

Detection Limit: The lowest concentration of gas that can be detected by the gas detector. This value should be reported by the equipment manufacturer.

Response Time: The amount of time required for the portable analyzer to display 95% of a step change in gas concentration on the data recorder.

- C. **Equipment:** The portable analyzer shall adhere to the standards tabulated below for each of the pollutants that it is intended to measure. All values in the table refer to maximum values. In addition to the parameters contained in the table, the minimum upper limit of the measurement range shall be equal to 1.5 times the emission limit for the species being measured.

Detector	Resolution	Error	Detection Limit	Response Time
CO	20 ppm	± 50 ppm	50 ppm	1 min
O ₂	0.5%	± 1.0%	0%	1 min
NO _x	2 ppm	± 5 ppm	5 ppm	1 min

- D. **Calibration:** Each gas detector shall be calibrated a minimum of once every six months and all instrument calibration data shall be kept on file with the monthly analyses. If the manufacturer recommends calibration more than once every six months, then the instrument calibration shall follow the manufacturer's recommended interval. Two calibration gases are required, the upper limit calibration gas shall have a concentration of 60-100% of the upper limit of the measurement range and the lower limit calibration gas shall have a concentration from 0-10% of the upper limit of the measurement range. Ambient air may be used as the upper limit calibration gas for O₂ and may be used as the lower limit calibration gas for both NO_x and CO. The system response time shall be determined during the gas detector calibration. The portable analyzer shall first be purged with ambient air. Calibration gas is then provided to the portable analyzer through a tubing length typically used during analysis. The time necessary for the data recorder to display a concentration equal to 95% of the final steady state concentration shall be recorded as the response time.

E. Measurement:

1. Concentration measurements shall not be taken until the sample acquisition probe has been exposed to the stack gas for at least 150% of the response time. Measurements shall be taken in triplicate.
2. If water vapor is not removed prior to measurement, the absolute humidity in the gas stream must be determined so that the gas concentrations may be reported on a dry basis. If water vapor creates an interference with the measurement of any component, then the water vapor must be removed from the gas stream prior to concentration measurements.
3. The concentration of NO_x is calculated as the sum of the volumetric concentrations of both NO and NO₂. The portable analyzer used to detect NO_x must either convert NO₂ to NO and measure NO, convert NO to NO₂ and measure NO₂, or measure both NO and NO₂. An NO₂ to NO converter is not necessary if data are presented to demonstrate that the NO₂ portion of the exhaust gas is less than 5 percent of the total NO_x concentration.

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APPENDIX C

SMAQMD Permit to Operate 2007

April 3, 2007

Stuart Husband
Regulatory Compliance Coordinator, Power Generation
SMUD
6201 S Street, MS-B355
Sacramento, CA 95817-1899

Dear Mr. Husband:

The attached Permit to Operate has been reviewed and permit conditions have been revised to reflect the SMAQMD's current air quality rules.

Your Permit to Operate is re-issued **with specific conditions**. If you have any questions regarding the permit conditions contact the SMAQMD. There is an appeal process for any disputed permit conditions, but you must file an appeal within 30 days of the Permit to Operate being issued.

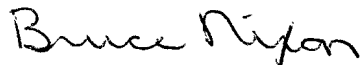
After this 30 day period, operation under this Permit to Operate shall be deemed acceptance of all the specified conditions.

Please make all equipment operators aware of the conditions on your Permit to Operate. SMAQMD staff will conduct periodic inspections of your facility to determine compliance with the conditions of your Permit to Operate and applicable air quality rules. Failure to comply with permit conditions and/or SMAQMD rules can result in civil/criminal penalties.

A copy of the Permit to Operate must be available at the location of the permitted equipment.

If you have any questions please contact me.

Sincerely,



Bruce Nixon, P.E.
Air Quality Engineer
phone: (916) 874-4855 (Mon. - Tue.)
fax: (916) 874-4899
email: bnixon@airquality.org

enclosure

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AIR QUALITY
MANAGEMENT DISTRICT

PERMIT TO OPERATE

Sacramento Cogeneration Authority
PO Box 15830
Sacramento, CA 95852-1830

Equipment Location: 5000 83rd Street, Sacramento

Permit No.	Equipment Description
12318(Rev03)	Boiler, auxiliary, Babcock & Wilcox, FM103-88, 90,000 lb/hr steam, 108.7 MMBTU/hr, natural gas fired, with a Todd Ultra Low NOx Rapid Mix Burner System.

SUBJECT TO THE FOLLOWING CONDITIONS:

GENERAL REQUIREMENTS

1. The equipment shall be properly maintained.
2. The SMAQMD Air Pollution Control Officer and/or authorized representatives, upon the presentation of credentials, shall be permitted:
 - A. To enter upon the premises where the source is located or in which any records are required to be kept under the terms and conditions of this Permit to Operate, and
 - B. At reasonable times to have access to and copy any records required to be kept under the terms and conditions of this Permit to Operate, and
 - C. To inspect any equipment, operation or method required in this Permit to Operate, and
 - D. To sample emissions from the source or require samples to be taken.
3. This Permit to Operate does not authorize the emission of air contaminants in excess of those allowed by Division 26, Part 4, Chapter 3, of the California Health and Safety Code or the rules and regulations of the SMAQMD.
4. A legible copy of this Permit to Operate shall be maintained on the premises with the equipment.

Date Issued: 11-08-2001
Date Revised: 04-03-2007
Date Expires: 08-22-2007 (unless renewed)

Larry Greene
SMAQMD Air Pollution Control Officer

by: Bruce Nixon

**SACRAMENTO METROPOLITAN AIR QUALITY MANAGEMENT DISTRICT
PERMIT TO OPERATE**

5. Malfunction - the SMAQMD Air Pollution Control Officer shall be notified of any breakdown of the emissions monitoring equipment, any engine equipment or any process which results in an increase in emissions above the allowable emissions limits stated as a condition of this permit or any applicable state or federal regulation which affects the ability of the emissions to be accurately determined. Such breakdowns shall be reported to the SMAQMD in accordance with the procedures and reporting times specified in SMAQMD Rule 602 - Breakdown Conditions; Emergency Variance.
6. Severability - if any provision, clause, sentence, paragraph, section or part of these conditions for any reason is judged to be unconstitutional or invalid, such judgment shall not affect or invalidate the remainder of these conditions.

EMISSION LIMIT REQUIREMENTS

7. The auxiliary boiler shall not discharge into the atmosphere any visible air contaminants other than uncombined water vapor, for a period or periods aggregating more than three minutes in any one hour, which are as dark or darker than Ringelmann No. 1 or equivalent to or greater than 20% opacity.
8. The auxiliary boiler emissions shall not exceed the following limits:

Pollutant	Maximum Allowable Emissions (averaged over a 3 hour period)	
	ppmvd at 3% O ₂	lb/hour (D)
ROC	-	0.41
NO _x	9 (A)	1.15
SO _x	-	0.08
PM ₁₀	-	0.54
CO	400 (A)	7.12

(A) except during periods of startup (B) and shutdown (C)

(B) Startup is defined as the period of time, not to exceed two hours, in which a unit is brought to its operating temperature and pressure immediately after a period in which the gas flow is shut off for a continuous period of 30 minutes or longer.

(C) Shutdown is defined as the period of time a unit is cooled from its normal operating temperature. The shutdown period shall be limited to two hours.

(D) ROC emission based on an ROC emission factor of 0.00377 lb/MMBTU and firing at full capacity.
NO_x emission based on NO_x data submitted in the permit application and monitoring data from the boiler's NO_x CEM system.

SO_x emission based on a SO_x emission factor of 0.0006 lb/MMBTU and firing at full capacity.

PM₁₀ emission based on a PM₁₀ emission factor of 0.00497 lb/MMBTU and firing at full capacity.

CO emission based on CO data submitted in the permit application and monitoring data from the boiler's CO CEM system.

**SACRAMENTO METROPOLITAN AIR QUALITY MANAGEMENT DISTRICT
PERMIT TO OPERATE**

9. Combined emissions from all equipment at the Sacramento Cogeneration Authority's facility, including start-ups and shutdowns, shall not exceed the following limits:

Pollutant	Maximum Allowable Emissions (lb/day)					
	Combined Cycle Gas Turbine 1A and Duct Burner	Combined Cycle Gas Turbine 1B and Duct Burner	Simple Cycle Gas Turbine 1C	Cooling Tower	Auxiliary Boiler	Total
ROC	43.2	43.2	28.3	NA	9.8	124.5
NOx	233	233	203.8	NA	27.6	697.3
SOx	7.7	7.7	6.5	NA	1.8	23.7
PM10	79.2	79.2	60	7	13.1	238.5
CO	113.4	113.4	85.1	NA	170.8	482.7

10. Combined emissions from all equipment at the Sacramento Cogeneration Authority's facility, including start-ups and shutdowns, shall not exceed the following limits:

Pollutant	Maximum Allowable Emissions				
	Quarter 1 (lb/quarter)	Quarter 2 (lb/quarter)	Quarter 3 (lb/quarter)	Quarter 4 (lb/quarter)	Annual (lb/year)
ROC	8,287	8,380	8,472	8,472	33,611
NOx	49,051	49,590	50,128	50,128	198,897
SOx	1,722	1,741	1,760	1,760	6,983
PM10	17,220	17,411	17,603	17,603	69,837
CO	29,758	30,082	30,407	30,407	120,654

EQUIPMENT OPERATION AND MONITORING REQUIREMENTS:

11. The auxiliary boiler shall not exceed an annual capacity factor of 80% based on heat input.
12. The boiler shall be fired on natural gas only.
13. Sacramento Cogeneration Authority shall operate a continuous emission monitoring (CEM) system, that has been approved by the SMAQMD Air Pollution Control Officer, for the auxiliary boiler emissions.
 - A. The CEM system shall monitor and record concentrations of NOx, CO and oxygen.

**SACRAMENTO METROPOLITAN AIR QUALITY MANAGEMENT DISTRICT
PERMIT TO OPERATE**

B. The CEM system shall comply with the U.S. EPA Performance Specifications (40 CFR 60, Appendix B, Performance Specifications 2, 3 and 4).

14. The Sacramento Cogeneration Authority shall operate a continuous parameter monitoring system that has been approved by the SMAQMD Air Pollution Control Officer that either measures or calculates and records the following.

Parameter to be Monitored	Units
Fuel consumption of the auxiliary boiler	MMBTU/hr of natural gas

RECORDKEEPING AND REPORTING REQUIREMENTS:

15. The following record shall be continuously maintained on site for the most recent five year period and shall be made available to the SMAQMD Air Pollution Control Officer upon request. Quarterly and yearly records shall be made available for inspection within 30 days of the end of the reporting period.

Frequency	Information to be Recorded
General	<p>A. Measurements from the continuous monitoring system.</p> <p>B. Monitoring device and performance testing measurements.</p> <p>C. Continuous monitoring system performance evaluations.</p> <p>D. Continuous monitoring system or monitoring device calibration checks</p> <p>E. Continuous monitoring system adjustments and maintenance.</p>
Hourly	<p>F. Auxiliary boiler natural gas fuel consumption (MMBTU/hr).</p> <p>G. Auxiliary boiler NO_x, CO, ROC, SO_x and PM₁₀ hourly emissions.</p> <p>i. For those pollutants directly monitored (NO_x and CO), the hourly emissions shall be calculated based on the CEM system required pursuant to Condition No. 13.</p> <p>ii. For those pollutants that are not directly monitored (ROC, SO_x, and PM₁₀), the hourly emissions shall be calculated based on an emission factor derived from the maximum hourly permitted emission rate divided by the maximum heat input capacity and then multiplied by the actual firing rate of the auxiliary boiler.</p> <p>H. Auxiliary boiler NO_x concentration (ppmvd at 3% O₂).</p>
Daily	<p>I. Total daily ROC, NO_x, SO_x, PM₁₀ and CO emissions from all equipment combined at the Sacramento Cogeneration Authority facility (lb/day).</p>
Quarterly	<p>J. Total quarterly ROC, NO_x, SO_x, PM₁₀ and CO emissions from all equipment combined at the Sacramento Cogeneration Authority facility (lb/quarter).</p>

**SACRAMENTO METROPOLITAN AIR QUALITY MANAGEMENT DISTRICT
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Frequency	Information to be Recorded
Yearly	K. Total yearly ROC, NO _x , SO _x , PM ₁₀ and CO emissions from all equipment combined at the Sacramento Cogeneration Authority facility (lb/year) L. Annual capacity factor of the auxiliary boiler based on heat input (%)

16. Submit to the SMAQMD Air Pollution Control Officer a written report which contains the following information.

Frequency	Information to be submitted
Quarterly - due by: January 30 April 30 July 30 October 30	A. Whenever the CEM system is inoperative except for zero and span checks. i. Date and time of non operation of the CEM system. ii. Nature of the CEM system repairs or adjustments. B. Whenever an emission occurs as measured by the required CEM system that is in excess of any emission limitation. i. Magnitude of the emission which has been determined to be in excess. ii. Date and time of the commencement and completion of each period of excess emissions. iii. Periods of excess emissions due to start-up, shutdown and malfunction shall be specifically identified. iv. The nature and cause of any malfunction (if known). v. The corrective action taken or preventive measures adopted. C. If there were no excess emissions during a reporting quarter. i. A report shall be submitted indicating that there were no excess emissions.

17. An ROC, NO_x, CO and CEM accuracy source test of the auxiliary boiler shall be performed once every calendar year.

- A. Submit a test plan to the SMAQMD Air Pollution Control Officer for approval at least 30 days before the source test is to be performed.
- B. The SMAQMD Air Pollution Control Officer shall be notified at least 7 days prior to the emission testing date.
- C. During the test(s), the auxiliary boiler is to be operated at >90% of the maximum firing capacity.
- D. The source test results shall be submitted to the SMAQMD Air Pollution Control Officer within 60 days from the completion of the source test(s).
- E. The Air Pollution Control Officer may waive the annual ROC source test requirement if, in the Air Pollution Control Officer's sole judgment, prior test results indicate an adequate compliance margin has been maintained.

SACRAMENTO METROPOLITAN AIR QUALITY MANAGEMENT DISTRICT
PERMIT TO OPERATE

Your application for this air quality Permit to Operate was evaluated for compliance with Sacramento Metropolitan Air Quality Management District (SMAQMD), state and federal air quality rules. The following listed SMAQMD rules are those that are most applicable to the operation of your equipment. Other rules may also be applicable.

<u>SMAQMD Rule No.</u>	<u>Rule Title</u>
201	General Permit Requirements
202	New Source Review
401	Ringelmann Chart
402	Nuisance
406	Specific Contaminants
411	Boiler NOx
420	Sulfur Content of Fuels

In addition, the conditions on this Permit to Operate may reflect some, but not all, requirements of these rules. There may be other conditions that are applicable to the operation of your equipment. Future changes in prohibitory rules may establish more stringent requirements which may supersede the conditions listed here.

For further information please consult your SMAQMD rulebook or contact the SMAQMD for assistance.

APPENDIX D

Property Owners Within 1000 Feet of the SCA Project

PROPERTY OWNERS WITHIN 1000 FEET OF THE SCA PROJECT

Owner Name	Owner Name 2	Tax Billing Address	Tax Billing City/ State	Tax Billing Zip
Central California Traction Co.		949 E Channel St	Stockton, CA	95202
Central California Traction Co.		949 E Channel St	Stockton, CA	95202
Procter & Gamble Manufacturing Co		Po Box 599	Cincinnati, OH	45201
Engineered Polymer Solutions, Inc.		930 W 1st St Ste 303	Fort Worth, TX	76102
Southdown Calif Cement, LLC	Cemex Acquisition Corp	Po Box 1500	Houston, TX	77251
Alta Plating Incorporated	Carol Strunk	1733 S St	Sacramento, CA	95811
Robert S Parks		Po Box 289	North Highlands, CA	95660
Hickey Strunk	Strunk Leslie H & Carol	1733 S St	Sacramento, CA	95811
Dieter Folk	Folk Michelle T	7010 Bucktown Ln	Vacaville, CA	95688
Cable & Kilpatrick, Inc.		960 Fulton Ave Ste 100	Sacramento, CA	95825
Hickey Strunk	Strunk Leslie H & Carol	1733 S St	Sacramento, CA	95811
Carol Strunk	Strunk Leslie H & Hickey Family	1733 S St	Sacramento, CA	95811
David R Warwick	Warwick Marianne A	5730 Bennett Valley Rd	Santa Rosa, CA	95404
David R Warwick	Warwick Marianne A	5730 Bennett Valley Rd	Santa Rosa, CA	95404
David R Warwick	Warwick Marianne A	5730 Bennett Valley Rd	Santa Rosa, CA	95404
Hbb Holding Company, Inc.		4751 Power Inn Rd	Sacramento, CA	95826
Hbb Holding Company, Inc.		4751 Power Inn Rd	Sacramento, CA	95826
Joseph Breault Properties LLC		4724 Winding Way	Sacramento, CA	95841
Cable & Kilpatrick, Inc.		960 Fulton Ave Ste 100	Sacramento, CA	95825
Cable & Kilpatrick, Inc.		960 Fulton Ave Ste 100	Sacramento, CA	95825
Hp Hood LLC		405 Howard St	San Francisco, CA	94105
Hp Hood LLC		405 Howard St	San Francisco, CA	94105
Air Products and Chemicals, Inc.		7201 Hamilton Blvd	Allentown, PA	18195
Air Products and Chemicals, Inc.		7201 Hamilton Blvd	Allentown, PA	18195
Alan L Shufelberger	Shufelberger Sherry M	Po Box 990861	Redding, CA	96099
Central California Traction Co.		949 E Channel St	Stockton, CA	95202
Trench Plate Rental Co		13217 Laureldale Ave	Downey, CA	90242
A/W Investments, LLC		8333 24th Ave	Sacramento, CA	95826

PROPERTY OWNERS WITHIN 1000 FEET OF THE SCA PROJECT (Continued)

Owner Name	Owner Name 2	Tax Billing Address	Tax Billing City/ State	Tax Billing Zip
Southern Pacific Transportation Co.		1400 Douglas St 1640	Omaha, NE	68179
Southern Pacific Transportation Co.		1400 Douglas St 1640	Omaha, NE	68179
Corp of President LDS Church		50 E North Temple Fl 22nd	Salt Lake City, UT	84150
Corp of President LDS Church		50 E North Temple Fl 22nd	Salt Lake City, UT	84150
Fruitridge Development Co		R Florin Perkins	Sacramento, CA	95826
Redding Roofing Supply		P O Box 861	Redding, CA	96099
Carl Haworth	Clough Kathryn	141 Olympic	Granite Bay, CA	95746
Redding Roofing Supply		Po Box 990861	Redding, CA	96099
C&S Logistics Sacramento and Tracy LLC		47 Old Ferry Rd	Brattleboro, VT	5301

Notes:

Data based on currently available Sacramento County Assessors Office information.

Leaseholder information is not included.